SOUTH COWDEN UNIT

AGREEMENT NO. DE-FC22-94BC14991

DESIGN AND IMPLEMENTATION OF A CO_2 FLOOD UTILIZING ADVANCED RESERVOIR CHARACTERIZATION AND HORIZONTAL INJECTION WELLS IN A SHALLOW SHELF CARBONATE APPROACHING WATERFLOOD DEPLETION

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DESIGN AND IMPLEMENTATION OF A CO_2 FLOOD UTILIZING ADVANCED RESERVOIR CHARACTERIZATION AND HORIZONTAL INJECTION WELLS IN A SHALLOW SHELF CARBONATE APPROACHING WATERFLOOD DEPLETION

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ABSTRACT

The work reported herein covers select tasks in Budget Phase II. The principle Task in Budget Phase II included in this report is Field Demonstration. Completion of many of the Field Demonstration tasks during the last report period enabled an optimum carbon dioxide (CO_2) flood project to be designed, economically evaluated, and implemented in the field. Field implementation of the project commenced during late 1995, with actual CO_2 injection commencing in mid-July, 1996. This report summarizes activities incurred following initial project start-up, towards the goal of optimizing project performance.

The current project has focused on reducing initial investment cost by utilizing horizontal injection wells and concentrating the project in the best productivity area of the field. An innovative CO_2 purchase agreement (no take-or-pay provisions, CO_2 purchase price tied to West Texas Intermediate (WTI) crude oil price) and gas recycle agreement (expensing costs as opposed to a large upfront capital investment for compression) were negotiated to further improve the project economics.

The Grayburg-San Andres section had previously been divided into multiple zones based on the core study and gamma ray markers that correlate wells within the Unit. Each zone was mapped as continuous across the field. Previous core studies concluded that the reservoir quality in the South Cowden Unit (SCU) is controlled primarily by the distribution of a bioturbated and diagenetically-altered rock type with a distinctive “chaotic” texture. The “chaotic” modifier is derived from the visual effect of pervasive, small-scale intermixing of tan oil-stained reservoir rock with tight gray non-reservoir rock. The “chaotic” reservoir rock extends from Zone C (4780'-4800') to the lower part of Zone F (4640'-4680'). Zones D (4755'-4780') and E (4680'-4755') are considered the main floodable zones, though Zone F is also productive and Zone C is productive above the oil-water contact.

During Budget Phase I, the Stratamodel computer program was utilized as the primary tool to integrate the diverse geologic, petrophysical, and seismic data into a coherent three dimensional (3-D) model. The basic porosity model having been constructed, critiqued and modified based on field production and detailed cross-section displays, permeability data was imported into the model, and a 3-D interpolation of the permeability was completed.

Also during Budget Phase I, a full-field reservoir simulation model was constructed covering all of the South Cowden Unit plus Fina’s Emmons Unit and a portion of Unocal’s Moss Unit, both of which border South Cowden Unit (SCU) on the north. Visual inspection of the porosity and permeability distribution in the geologic model indicated that the E zone interval could be separated into four units. These four layers in the E, in addition to the F layer, upper D layer, and the C layer, comprise the seven flow units imported into the existing reservoir simulator to create a new, more heterogeneous description. Data from all additional wells drilled in the project area under Phase II of the

Project were incorporated in the model. The history match was updated, and a new simulation model run used to update CO_2 flood performance forecasts and to optimize final horizontal well locations, orientation, and completion strategy.

Under Phase II of the project, one additional reservoir characterization well was drilled within the project area. Routine whole core analyses measurements were completed. The cores were slabbed for use in petrographic studies by Phillips' Bartlesville personnel, to include macroscopic core description and thin sections. Two vertical CO_2 water alternating gas (WAG) injection wells were drilled in December, 1995. The first was completed as a marginal oil producer, then converted to CO_2 injection during the summer of 1996, when the pipeline and injection facilities were completed. The second well was also completed and placed on CO_2 injection at that time. CO_2 injection commenced in these vertical (WAG) injection wells during mid-July, 1996.

The drilling and completion operation for the horizontal CO_2 WAG injector Well 6C-25H began March 17, 1996, and was completed in 28 days. The drilling and completion operation for Well 7C-11H commenced April 14, 1996, and was completed in 20 days. The design parameters and the actual results matched exceptionally well. Water injection in these wells commenced in early July, with CO_2 injection starting in early August.

Three additional leaseline vertical WAG injection wells were drilled during late 1996 along the northern leaseline with the Emmons Unit. The Department of Energy (DOE) participated in the drilling of two of these, including Wells Nos. 6-26W and 6-27W, which were placed on water injection during January, 1997. The DOE did not share in the drilling of the third well, Well 6-28W, which was also placed on water injection during early 1997.

Injection profile surveys were run under both water and CO_2 injection in the horizontal injection wells. Both the injection profile log and subsequent fall-off pressure test in horizontal injection Well No. 6C-25H confirmed injection over an approximate 250' interval, well-distributed along the horizontal section. However, the same evaluation tools indicated the possibility of a fracture intersecting the toe of the openhole section in northwesterly horizontal injection well, Well No. 7C-11H. Further work is planned to correct potential out-of-zone injection in that well, scheduled for 1998.

Injection profile surveys run in the three leaseline injection wells indicated out-of-zone injection requiring remediation in all the wells. That work is also planned for third quarter, 1997. Water injection was commenced in these wells during second quarter, 1997.

Two additional production wells were drilled during this reporting period, the first as a replacement well and the second to tighten the spacing in an important area of the Unit.

EXECUTIVE SUMMARY

In June of 1994, Phillips Petroleum Company received a financial award from the Department of Energy (DOE) to conduct a project in the South Cowden Unit (SCU) in Ector County, Texas. The purpose of the project is to design an optimum carbon dioxide (CO_2) flood project utilizing advanced reservoir characterization and CO_2 horizontal injection wells, demonstrate the performance of this project in the field and transfer the information to the public so it can be used to avoid premature abandonment of other fields. The producibility problem in the unit is that it is a mature waterflood with a water cut exceeding 95%. Oil must be mobilized through the use of a miscible or near-miscible fluid in order to recover significant additional reserves. Also, because the unit is relatively small, it does not have the benefit of economies of scale inherent in the very large scale projects which have historically produced most of the CO_2 project oil. Thus, new and innovative methods are required to reduce the investment and operating costs. Two primary methods to be used in this work to accomplish improved economics are the use of reservoir characterization to restrict the flood to the high quality rock in the unit and the use of horizontal injection wells to cut investment and operating costs through centralization.

The project consists of two budget phases. Budget Phase I started in June, 1994 and ended late June, 1996. During this phase, the Reservoir Analysis and Characterization Task and the Advanced Technology Definition Task were completed. Completion of these tasks enabled the project to be designed, evaluated, and an Authority for Expenditure (AFE) for project implementation to be generated and submitted to the working interest owners for approval. Budget Phase II consists of the implementation and execution of the project in the field. Phase II will terminate in January of 2001.

Budget Phase II commenced with the drilling of the third reservoir characterization well (RC-3) during November and December, 1995. Two vertical CO_2 water alternating gas (WAG) injection wells were drilled in December, 1995. Two horizontal CO_2 WAG injection wells were drilled and completed during March and April, 1996. These wells were designed to mechanically optimize well injection performance and useful well life. Two additional production wells were also drilled and completed in late 1995. These wells were needed to drain areas of the field offsetting the proposed horizontal injection wells, replacing old wells which had been previously plugged and abandoned.

Additional early Phase II work commenced during the first half of 1996 included petrographic core studies on specific cores obtained during the drilling of the third Reservoir Characterization Well (RC-3).

Phase II work continued through the current reporting period, with initiation of CO_2 injection in the two vertical WAG injection wells and the two horizontal WAG injection wells, at a rate of approximately 8.0 million standard cubic feet per day (MMscfd) within the SCU project area. Three additional leaseline WAG injection wells were drilled and completed along the north boundary with the Emmons Unit. Injection profile problems were identified during early 1997, and work is planned to remedy out-of-zone injection prior to commencing CO_2 injection.

Two additional production wells were drilled during the current reporting period, the first as a replacement well and the second to tighten the spacing in an important area of the Unit.

Cumulative CO_2 injected as of June 30, 1997, is 2,606,823 thousand standard cubic feet (Mscf) CO_2. The average daily CO_2 injection rate during June, 1997, was 8.8 MMscf CO_2 per day.

INTRODUCTION

Summary of Project Objectives

The principal objective of this project is to demonstrate the economic viability and widespread applicability of an innovative reservoir management and carbon dioxide (CO_2) flood project development approach for improving CO_2 flood project economics in shallow shelf carbonate (SSC) reservoirs.

Most of the incremental tertiary oil production from CO_2 projects in SSC reservoirs to date has come from a few, very large-scale projects where the sizable economies of scale inherent in this type of development can greatly improve project economics. In fact, the five largest CO_2 miscible flood projects implemented in SSC reservoirs account for over one-half of the total incremental oil production attributable to CO_2 miscible flooding in 1992 in the United States.

This project shall demonstrate the economic viability of the advanced technology of developing a CO_2 flood project utilizing multiple horizontal CO_2 injection wells drilled in several directions from a central location. The use of several horizontal injection wells drilled from a centralized location will reduce the number and cost of new injection wells, wellheads, and equipment; allow concentration of the surface reinjection facilities; and minimize the costs associated with CO_2 distribution system. It is anticipated that the proposed advanced technology will show improved CO_2 sweep efficiency and will significantly reduce the capital investment required to implement a CO_2 tertiary recovery project relative to conventional CO_2 flood pattern developments using vertical injection wells. This technology will be readily transferred to the domestic oil industry and should introduce CO_2 flooding as an economically viable technology option for smaller SSC reservoirs and for independent operators.

Summary of Field Details

The South Cowden Unit (SCU) is located in Ector County, Texas and produces primarily from the Grayburg and San Andres Formations of Permian Age. These formations were deposited in shallow carbonate shelf environments along the eastern margin of the Central Basin Platform. The primary target for CO_2 flood development under the proposed project is a 150-200 foot gross interval within the San Andres located at an average depth of approximately 4550 feet. The original oil in place (OOIP) for the South Cowden Unit is estimated to be less than 180 million barrels. The field was discovered in 1940 and unitized for secondary recovery operations beginning in 1965.

After approximately 12 months of CO_2 injection, the Unit is producing 405 barrels of oil per day (BOPD) at a water cut in excess of 94% from 48 active producers and 20 active injectors. Approximately 75 BOPD of production response deemed to be as a direct result of the CO_2 injection has been seen in six wells immediately adjacent to the horizontal injection wells. Ultimate recovery for primary plus secondary is still estimated at just over 35 million stock-tank barrels of oil (STBO), or approximately 20 percent of original oil in place (OOIP). Tertiary oil resulting from the CO_2 project is estimated at 12 million stock-tank barrels (STB), or 8% within the project area.

Project Description

The purpose of this project is to demonstrate the economic viability and widespread applicability of an innovative management plan for a CO_2 flood project, utilizing advanced reservoir characterization and CO_2 horizontal injection wells. The South Cowden Unit (SCU) is an example of a very mature waterflood, rapidly approaching its economic limit. Past waterflood performance was considered good; however, field average water cut at the project start-up exceeded 95 percent, leaving tertiary recovery as the only remaining prospect for extending the field life and recovering the remaining oil. Advanced reservoir characterization has been used to define the best areas within the field, which are likely to perform well under CO_2 operations.

Standard methods of CO_2 flooding are not viable under the current oil price scenario due to the limited aerial extent of the SCU. Standard methods include the traditional fully-confined nine- or five-spot patterns. In the case of SCU, a feasibility study was completed in which the field was CO_2 flooded with 20-acre five-spots (assumed because of the existing well configuration). The feasibility study indicated that the South Cowden Unit was an excellent technical CO_2 flood candidate; however, the large capital investment required restricted its economic viability. New and innovative methods were required to reduce the overall investment required to improve the economic viability. These new methods, however, carried additional risk.

The innovative approach chosen for the study was to CO_2 flood the South Cowden Unit with multiple horizontal injection wells from a centralized location. Preliminary studies indicated that significant investment cost reduction could be realized through lower overall drilling costs (fewer wells) and reduced surface injection line requirements, and operating costs reductions could be obtained through a reduction in re-injection costs. Improved sweep efficiency from the horizontal injection wells are expected to result in increased oil recoveries. Increased technical risks inherent in the project include the injection distribution along the horizontal section of the horizontal well and overall vertical coverage within the given horizontal well. Contingency plans for dealing with the technical risks were also developed. Advanced reservoir characterization has been essential in optimizing the final project design. At the conclusion of the project, a complete methodology for economical tertiary flooding of small SSC reservoirs will be established, allowing other operators to implement similar strategies for their own fields.

Summary of Progress

A CO_2 flood project for the South Cowden Unit (SCU) has been designed, evaluated, proposed to the working interest owners, approved for field implementation and fully implemented. Full-field implementation of the CO_2 project was completed in mid-July, 1996, with the initiation of CO_2 injection in the two vertical injectors.

Work on the project was initiated in June of 1994 with the Reservoir Analysis and Characterization Task, which were used to develop a three-dimensional (3-D) geologic reservoir description. An adequate reservoir description was assembled in early 1995 to initiate simulation studies for project design and performance forecasting.

The second major step in the process was defining the Advanced Technology Definition Task. This task was divided into seven subtasks, including Special Laboratory Studies; Screening Studies to Identify Suitable Gelled Polymers for Profile Modification; Advanced Geostatistical Studies; Reservoir Simulation for Project Design and Performance Forecasting; Design of the Horizontal Well Scheme and the Final Project Development Plan; Design of Upgrades and/or Additions to Production, Water Injection, CO_2 Injection, Compression, Water Disposal, Automation, Electrical and Cathodic Protection Facilities; and Investment Cost Forecast, Operating Cost Forecast and generation of the Authority for Expenditure (AFE). This AFE was approved and field implementation of the project (Budget Phase II) began in late October of 1995. From late October, 1995, through June 30, 1996, work included in Budget Phase I was being finished-up while implementation work included in Budget Phase II was being done.

Work on Budget Phase II was defined into two tasks: Field Demonstration and Technology Transfer, Reporting, and Project Management Activities for Budget Phase II. Field Demonstration during the current reporting period encompasses the project implementation subtasks, including injection testing and injection initiation in horizontal injection Wells Nos. 6C-11H and 7C-11H along with vertical injection Wells Nos. 2-26W and 2-27W; the drilling and testing of three additional leaseline WAG injection wells and two production wells; the conversion of three wells for water injection; the reactivation of seven shut-in wells for production; the remediation of six existing production wells; the purchase of CO_2; the operation of the recycle compression and injection facilities; and the monitoring of project performance. Technology transfer, reporting and project management related to Budget Phase II primarily include the media opportunities related to the project start-up celebration, preparation of technical papers, and participation in industry events and the 1997 Department of Energy (DOE) project review.

DISCUSSION

Background Information

Budget Phase Two consists of Tasks V-VI as defined in the Revised Statement of Work (RSOW). The RSOW contains fourteen primary subtasks in Task V, some of which were initiated in the past reporting period, and some of which will be reported on in this annual report. Task VI contains six primary subtasks, including Technology Transfer, Reporting, and Project Management Activities related to Budget Phase Two.

PHASE II

TASK V FIELD DEMONSTRATION

Testing of Horizontal Injection Wells Nos. 6C-25H (H-1) and 7C-11H (H-2)

Prior to being placed on CO_2 injection, injection profile surveys and falloff tests were conducted under water injection to verify that we had obtained an acceptable distribution of injection along the lateral section and to determine the mechanical condition and completion efficiency in the horizontal wells.

Injection Testing while under Water Injection

The injection profile work for the first horizontal well, Well No. 6C-25H, was done by Cardinal Surveys Company. This consisted of a continuous flowmeter, quartz pressure sensor, temperature surveys, capacitance and gamma ray probe conveyed on 1.25" coiled tubing. Good results were obtained even though the survey was done at relatively low injection rates under a very small pressure differential into the formation. Injection and shut-in temperatures indicated fluid movement through the horizontal, openhole interval out to approximately 6600' wireline (WL) depth with a major fluid loss at 5340'-5480' WL. The logs also indicated lesser fluid losses at 4940'-4990' (near the casing shoe), 5185'-5275', 5655’-5695, 5775'-5870' and 6210'-6295' WL. The gamma ray passes and tagged fluid also supported these conclusions. The one-hour shut-in temperature log and concurrent gamma ray pass indicated crossflow from 6638'-6295' WL while the well was shut-in. It was also noted that the trailing edge of the tagged interface showed tubular buildup.

Repeated temperature passes showed a 1-1/2 degree cooling anomaly from 6650'-6800' WL. An influx of fluid coming from the formation into the end of the horizontal section appeared to be the most plausible cause. Because no other conclusive data from other log sensors could be found, it was concluded that the influx rate was approximately equal under both shut-in and flowing conditions. Initial injection profile logging results are presented in Figure 1.

Injection pressure measurements and a pressure falloff test were also run during the water injection period in Well No. 6C-25H. High-quality falloff data were obtained. Initial pressures matched closely with the simulation model predictions along the horizontal traverse and permeability data derived from radial flow periods matched well with the history-matched permeabilities in the model. The length of the effective intervals (250’) taking fluid derived from model verification matching agreed with the injection profile survey results. The pressure falloff results indicated a good acid stimulation had been obtained from the coiled tubing acid wash completion in the horizontal section. Based on the favorable results in the injection profile and falloff data, the well was placed on CO_2 injection during early August and slowly brought up to capacity injection at a bottomhole injection pressure slightly below the calculated formation parting pressure of 2600 pounds per square inch (psi), equivalent to 0.57 psi/ft fracture gradient (determined by a microfracture test on SCU Well 6-21 during 1994. The injection rate stabilized very close to the expected rate forecast in the model.

The injection profile survey on the second horizontal well, Well No. 7C-11H, was conducted by Halliburton using a different procedure. They opted to run a logging and injection program wherein coiled tubing and wireline were run in the injection well simultaneously with a Y-block and coiled tubing side-entry assembly attached to the coiled tubing below the spot valve. The tool consisted of positive and negative gamma-ray and temperature tool. A slug of more than one gallon of radioactive gel with 50 micron sand was used rather than the standard injection procedure of 1 cubic centimeter (cc) per station. A flowing temperature log and velocity shots were used to determine fluid entry. Results of the second injection profile survey were somewhat ambiguous and difficult to interpret. Halliburton’s interpretation indicated injection fluid movement throughout all but the last 150 feet near the toe of the horizontal interval. Based on the flow rate and the gamma ray logs, in-house interpretation of the results indicated most of the fluid was being injected into a fracture or high permeability zone at the toe of the well, between 6025' and 6100'. These logging results are presented in Figure 2.

A pressure falloff test was also run in Well No. 7C-11H while on water injection. This test did not show the same behavior as demonstrated in the first well. The test showed early linear flow behavior rather than early radial flow as in the first horizontal well. This second well was drilled approximately normal to the preferential parting direction indicated in earlier micro-frac tests conducted in two reservoir characterization wells. The injection pressure had been limited to pressures several hundred pounds per square inch (psi) below the parting pressure while on water injection. One possible explanation for the falloff test behavior is that this second well may have intersected a parting plane from one of several nearby old injection wells. Before proceeding to CO_2 injection, it was decided to run a step rate test followed by an additional falloff test in this well. The step rate test showed a shift toward linear flow behavior and possible fracture extension above 2600 psi bottomhole injection pressure.

Multi rate analysis of the steprate test data on Well No. 7C-11H (shown in Figure 3) indicated a significant shift in the well’s injection behavior at bottomhole injection pressures above 2590 pounds per square inch absolute (psia) at 4675 feet true vertical depth (TVD); some fracture propogation extension was indicated at injection pressures above this level. For this reason, the surface injection pressure during CO_2 injection was set at 1050 pounds per square inch gauge (psig) on this well initially. The surface CO_2 injection pressure of 1050 psig would keep the bottomhole injection pressure at or slightly below 2590 psia at 4675 feet TVD.

Low-volume injection of CO_2 in the horizontal injection wells commenced in early August, following the pressure and injection profile testing. Higher-volume CO_2 injection into Wells Nos. 6C-25H and 7C-11H commenced August 14, and August 29, 1996, respectively.

Injection Testing while under CO_2 Injection

An additional injection profile survey was run on both horizontal wells during the initial CO_2 injection period. These injection profile surveys were needed to evaluate CO_2 injection performance and assess the lateral and vertical distribution of injected fluids.

The injection profile on Well 6C-25H indicated fairly uniform distribution of injection fluids under CO_2 injection, confirming the profile logging results obtained under water injection. Injection and shut-in temperature runs indicated fluid movement through the horizontal, openhole completion out to approximately 6620' WL, with a major loss at 5340'-5480' WL in Well 6C-25H. Injection temperatures, shut-in temperatures, injection capacitance, and shut-in capacitance logs indicated water cross-flowing from the end of the horizontal section to approximately 6620' WL. Shut-in capacitance logs also showed a progression of water entering the wellbore from about 6880' WL and an area near the major fluid loss at 5340'-5480' WL, filling the low areas of the wellbore, as indicated by the deviation survey. The last shut-in capacitance run showed the water level to have risen to a point where it was spilling-over into the middle section of the wellbore. Results from injection logging during CO_2 injection in Well 6C-25H are in Figure 4.

In contrast to the good injection profile seen in Well 6C-25H, injection and shut-in temperature passes in Well 7C-11H indicated possible fluid loss out the toe of the horizontal section. This interpretation was based on only a .25 degree temperature change at the toe of the horizontal section. This minor change in temperature could also, however, be caused by a rising water level in the horizontal wellbore. The capacitance log run indicated a CO_2/water interface at approximately 6210'-6200' WL while the well was on injection. The one-hour shut-in pass showed the interface to have moved to approximately 6140' WL. The two-hour shut-in pass indicated water throughout the entire openhole section. It is important to note that the tools were not centralized; therefore, these readings do not necessarily prove that the wellbore was full of water. They merely indicate that there is some amount of water in all the openhole section during the shut-in periods. These logging results are included as Figure 5.

A fracture had been suspected earlier as a result of the falloff and step rate testing, but was further suggested by the profile log under CO_2 injection. The information obtained from the injection profile logs will be used for implementation of mobility control measures during 1998, particularly in light of the results of the 7C-11H log.

Injection in Vertical Wag Injection Wells Nos. 2-26W and 2-27W

Water injection commenced in vertical WAG injection Wells Nos. 2-26W and 2-27W in early July, 1996. Bottom-hole pressure surveys were run in both these vertical injection wells during late July, immediately prior to commencing CO_2 injection. CO_2 injection began July 19, 1996 in Well No. 2-26W, at an initial wellhead pressure of 890 psig and injection rate of 200 thousand standard cubic feet per day (Mscfd). CO_2 injection commenced July 22, 1996 in Well No. 2-27W, at an initial wellhead pressure of 1000 psig and injection rate of 200 Mscfd.

Drill two vertical WAG injectors along South Cowden Unit boundary - approved under Amendment No. A007 to the Cooperative Agreement for inclusion in Phase II funding

During fourth quarter 1996, three vertical WAG injection wells were drilled along the north boundary with the Emmons Unit. The reservoir in this area is higher on structure than that portion of the reservoir in the vicinity of the previously mentioned horizontal WAG injection wells. The advantageous structural position provides additional pay sections. Horizontal wells would not provide for injection into all the productive zones because of permeability barriers between zones.

Vertical WAG injection Wells Nos. 6-26W and 6-27W were placed on water injection during January, 1997. Injection profile surveys were run while on water injection during early February, 1997.

Injection Profile Surveys while on Water Injection

The injection survey on Well 6-26W indicated communication between a water sand at 4344’-4355' and casing perforations 4568’-4572' and 4578’-4582’. During the shut-in period, the log indicated that flow from the water sand was entering the wellbore through the perforations in communication at a rate of 35 barrels per day (BPD) and was cross-flowing into the selectively perforated interval 4592’-4726'.

The injection survey also suggested that the selectively perforated intervals below 4700' (4709’-4711’, 4716’-4718’, and 4724’-4726') were taking approximately 15% of the injection water with evidence of downward channeling. A remedial workover was proposed to squeeze the selectively perforated interval 4709’-4726' and the selectively perforated interval 4568’-4582' in an effort to limit out-of-zone injection.

A workover was performed during early April, 1997, to conventionally squeeze cement the lower thief zone (4709'-4726') below a retainer at 4701' and then squeeze cement the upper perforations at 4568'-4582'. After three attempts to squeeze the upper zone, the well pressure tested in the upper zone and the well was placed back on water injection.

A subsequent water injection profile survey was run during June which indicated that the upward channel had successfully been plugged; however, virtually one hundred percent (100%) of the injected water was now going out the bottom of the well. A foamed cement job was then performed during late June to stop the out-of-zone injection, and the well was reperforated across the E and upper F zones (4618'-4638'). The job appeared to have been successful as planned, and the well was then placed on carbon dioxide (CO_2) injection. A subsequent injection profile will be run in third quarter to confirm the success of the foamed cement job.

The injection log run on Well 6-27W indicated 50-60% of the injection volume was leaving the wellbore through the perforated interval 4746'-4748', which had been perforated below the oil-water-contact at approximately -1800' subsea (ss). The injection survey also indicated limited water injection occurring above 4686'. A foamed cement job is planned during third quarter pending evaluation of the success of the procedure in Well 6-26W.

<u>Tracer Test on Well 6-28W</u> (Not included in DOE funding)

During the drilling of vertical WAG injection Well 6-28W, oil shows were seen in the drilling returns; however, when placed on a production test during late January, the well produced 70% CO_2 cut in the produced gas. This gave concern that CO_2 was by-passing contact with reservoir rock through the suspected fracture in the toe region of the northwesterly horizontal WAG injection Well 7C-11H. In order to test this hypothesis, a tracer test was attempted between the two wells.

On February 25, 1997, a sulphur hexaflouride (SF_6) tracer test was run on WAG injection Well 7C-11H, with produced gas samples being pulled from Well 6-28W. A trace of tracer gas was found in Well 6-28W within nine (9) hours of injection; however, no additional SF_6 tracer was encountered upon subsequent monitoring. Although first results seemed to confirm that a direct channel exists from the horizontal injector to Well 6-28W, further investigation of the sampling techniques indicate that the sampling may have been tainted, rendering the test results inconclusive. Further tracer testing is planned for late 1997 to further delineate remediation possibilities.

Drill multiple producing wells

Two new producing wells were drilled during fourth quarter, 1996, including Wells Nos. 7-13 and 7-15. Well No. 7-13 was drilled as a replacement well for plugged and abandoned production Well No. 7-06. Well 7-15 was drilled to improve the spacing in the northern portion of Section 18. This work was originally scheduled for 1997. Production graphs of these two wells since completion are included as Figures 6 and 7.

Initial completion tests are summarized as follows:

	----------AFTER----------			
	BOPD	BWPD	MCFPD	
SCU 7-13	23	87	0	Oct. 21, 1996
SCU 7-15	25	178	2	Oct. 18, 1996

Convert Three wells for Water Injection

During this reporting period, three wells were converted to water injection:

	----------BEFORE--------			----------------------AFTER---------------------------
Well	BOPD	BWPD	MCFD	
SCU 5-02 (Mar.,1997)	12	735	3	Injecting @ 690 BWPD and 720 psig
SCU 5-08 (Nov.,1996)	6	60	3	Injecting @ 250 BWPD and 560 psig
SCU 8-18 (Nov.,1996)	6	176	1	Injecting @ 518 BWPD and 750 psig

Graphs of daily water injection volumes since conversion to injection are included as Figures 8-10.

Re-Activate Seven Shut-in Wells for Production

During the reporting period, seven temporarily abandoned wells were reactivated:

	----------------AFTER-----------------			
	BOPD	BWPD	MCFPD	
SCU 6-20	11	75	4	Oct. 19, 1996 (6-02?)
SCU 7-02	5	119	0	Sept 30, 1996
SCU 7-05	5	220	1	Oct. 8, 1996
SCU 7-10	1	183	17	February, 1997
SCU 2-20	0	250	0	March, 1997
SCU 6-19	0	412	0	March, 1997
SCU 8-13	0	202	0	March, 1997

Production graphs of these seven reactivated wells are included as Figures 11-17.

Workover or Recondition Existing Wells (Not included in DOE funding)

During fourth quarter 1996, five wells were checked for fill and acidized; during first quarter 1997, additional perforations were added to Well 6-23, and the well was then acidized:

	-------BEFORE--------			----------AFTER-----------			
	BOPD	BWPD	MCFD	BOPD	BWPD	MCFD	
SCU 2-21	5	40	1	6	98	3	Nov. 10, 1996
SCU 2-24	7	38	1	9	63	2	Nov. 20, 1996
SCU 6-06	3	40	1	3	148	1	Dec. 12, 1996
SCU 2-08	6	90	1	13	128	1	Dec. 12, 1996
SCU 8-02	10	59	1	8	81	0	Dec. 4, 1996
SCU 6-23	1	0	48	1	249	1	March 1997

During second quarter 1997, three wells were acid stimulated. The results follow:

	----------BEFORE--------			----------------------AFTER--------------------			
Well	BOPD	BWPD	MCFD	BOPD	BWPD	MCFD	Comments
SCU 7-01	24	116	116	31	170	100	May, 1997
SCU 7-05	4	212	1	5	385	1	May, 1997
SCU 7-10	3	62	6	17	116	26	April, 1997

The DOE does not share in the costs of these acid stimulation jobs, which were deemed necessary as a result of updated reservoir simulation modeling to increase overall Unit production and throughput volumes. Production graphs of each of these wells is included in Figures 18-20.

Construct, Modify, and Upgrade Facilities for Injection and Production

Purchase Land, Install Perimeter Fence and H_2S Monitors

All of the required private lots in Section 17 of the South Cowden Unit were purchased during the summer of 1996. The sixth lot could not be obtained for a reasonable price; hence, the lot was not purchased. Extra precautionary monitors and alarms were installed along the lot line to protect the owner. This was discussed and approved by the Texas Railroad Commission (TRRC) to meet Rule 36 requirements.

The main 250-acre tract of land where CO_2 flood facilities are located was leased until the purchase of the land was finalized in late 1996.

Twenty-one hydrogen sulfide (H_2S) premise monitors were installed and are operational. An additional H_2S monitor along the perimeter fence behind the private lot that could not be purchased was added. If H_2S is detected by any of the monitors, an alarm is sent via radio to the Phillips Petroleum Odessa office South Cowden Unit (SCU) Supervisory Control and Data Acquisition (SCADA) computer, which in-turn sends a message to an operator on-call who will have an alpha-numeric pager. If the operator on-call cannot be reached, a list of people will be called until someone acknowledges the alarm.

Construction of the perimeter fence was completed. The fence was constructed to prevent public entrance into the project area, provide protection from exposure to H_2S and protect against vandalism. The fence was completed after all of the private lots were purchased.

Construct Injection Facilities

Installation of injection runs to all four of the CO_2 WAG injection wells was completed during August, 1996. Installation of injection runs to the water injection wells was completed prior to injection initiation in Wells Nos. 5-02, 8-18, and 5-08.

Installation of the injection facilities was completed in July, 1996, along with construction and installation of the H_2O and CO_2 (WAG) manifold. Since completion of the manifold with the CO_2/water meters, the meters were necessarily modified to improve CO_2 measurement and control.

The replacement of the old water injection system was completed with the installation of the lateral to injection Well No. 5-02.

Modify or Upgrade Production Facilities

Construction of the new Tract 6 Satellite facility is complete.

Construct Compression Facilities

Production Operators, Inc. (POI) completed construction of their re-injection facility on June 21, 1996. The facility was idle until December, 1996, when CO_2 production increased enough to justify operating the compressors.

Install Cathodic Protection

No additional field work has been completed this reporting period on the installation of cathodic protection. Evaluation of the collected data from the well logs is ongoing and redesign of the system utilizing the new data continues. A decision not to install the field-wide cathodic protection was made during fourth quarter 1996.

Install Supervisory Control and Data Acquisition (SCADA) Equipment

The SCADA system has been installed and is operating. Installation of producing well pump-off controllers is complete.

Purchase CO_2 and Operation of Recycle Compression

No tertiary response was anticipated through model simulation until the second quarter of 1997. However, production was continually monitored for CO_2 content in the produced gas stream. Significant CO_2 production commenced during the fall of 1996 in Wells Nos. 7-05, 6-22, 6-24 (RC-3), 6-03 and 6-07. The compression/recycle facilities were necessarily started-up in December 1996, with the recycle gas being injected primarily in Well 2-26W.

The total volumes injected in all four SCU injection wells for the reporting period were:

GAS INJECTION - Mscf of CO_2

	Jul 96	Aug 96	Sep 96	Oct 96	Nov 96	Dec 96
Monthly				242,743	269,465	276,626
Daily Average			7,830	8,982	8,923	
Cumulative				576,066	845,531	1,122,157

GAS INJECTION - Mscf of CO_2 (CONT).

	Jan 97	Feb 97	Mar 97	Apr 97	May 97	Jun 97
Monthly	236,091	230,633	263,268	246,126	243,854	264,694
Daily Average	7,616	8,237	8,493	8,204	7,866	8,823
Cumulative	1,358,248	1,588,881	1,852,149	2,098,275	2,342,129	2,606,823

Although no significant tertiary response was anticipated until mid-1997, incremental oil production resulting from CO_2 injection was sustained at approximately 70 BOPD during second quarter, 1997, in the near vicinity of the horizontal injection wells from production Wells Nos. 6-17, 6-22, 6-24, 7-01 and 7-08.

A summary of quarterly average production and injection follows:

	----------PRODUCTION--------			------------INJECTION------------	
Qtr	BOPD	BWPD	MCFD	BWID	Mscfd CO_2
1st 1996	375	3861	88	4520	0

	----------PRODUCTION--------			------------INJECTION------------	
2nd 1996	356	3526	89	4208	0
3rd 1996	337	4301	91	4144	3623
Qtr	BOPD	BWPD	MCFD	BWID	Mscfd CO_2
4th 1996	375	4907	105	4900	8674
1st 1997	442	5837	611	5837	8111
2nd 1997	425	6462	929	5710	8293

Update Performance Predictions and Re-evaluate Design Premises During the First 12 months of CO_2 Injection

The South Cowden full-field simulation model was updated to incorporate the exact project development and operating schedule as implemented during the first 12 months of project operations. The original simulation model was adjusted to reflect the details of the actual locations, completions, and timing of newly drilled, reactivated, and recompleted wells in the CO_2 flood project area. No additional history matching changes were made to the simulation model reservoir description used in making the original project forecasts.

Figure 21 shows a comparison of actual Unit performance versus (vs.) model forecast performance under both the originally premised project operation and implementation schedule and under the actual project operations and implementation schedule. The original project implementation schedule premised all new drilling, well work, facilities upgrades, etc. for the project would be completed by the premised July 1, 1996, CO_2 injection start date for the project. While all new wells were drilled and completed as scheduled, the actual startup of injection and production operations was delayed in some wells due to well testing, conducting profile surveys, etc. Also, reactivation of several shut-in producers was delayed several months compared with the premised implementation plan due to logistical considerations. The productive capacity of several reactivated production wells was initially significantly less than was premised in the original forecasts (based on the capacity of each well prior to shut-in). These variances in project operations and the delays in the project implementation schedule compared with the originally premised development plan had an unexpectedly large impact on the first twelve months CO_2 flood response.

Figure 22 shows the simulation model forecast gas injection rates in comparison with the actual measured CO_2 injection rates during the first year of project operations. The actual and forecast rates agree fairly well, however the actual injection schedule lagged the premised forecast by about three months. Figure 23 shows a comparison of forecast vs. actual injection rates for the individual CO_2 injection wells in the project in the first quarter of 1997. The relative injection rates of the two horizontal wells can be compared with injection rates into the two vertical wells. One of the horizontal wells (7C-11H) was rate constrained to 3.5 MMscfd during this period because most of the injected fluid was seen leaving the horizontal section through one short interval, indicating a probable fracture or thief zone at this point. Subsequent falloff testing and injection profile surveys indicated that there was a possible fracture at this point in the horizontal Well 7C-11H. Figure 24 compares the actual monthly produced gas rates to the forecast gas production rates. Actual gas production was slightly higher than the simulation model forecast.

Based on results of model forecasts vs. actual field performance, individual well responses, and injection profile data, remedial actions were recommended to remedy suspected problems with injection profiles and inadequate production capacity in certain wells. Specific recommendations are planned for implementation during third quarter 1997 and 1998 to stimulate selected wells and conduct additional conformance work to improve injection profiles in the CO_2 injection wells, particularly in the SCU horizontal injection Well 7C-11H.

As more data become available on the CO_2 production response in the South Cowden reservoir, further adjustments will be made to the simulation model reservoir description to match field performance and the CO_2 flood forecasts will be updated periodically. Based on these results, some adjustment of the reservoir management program may be advisable at South Cowden to optimize performance of the CO_2 project.

TASK VI TECHNOLOGY TRANSFER, REPORTING, AND PROJECT MANAGEMENT

Technology Transfer

During late 1996, a paper entitled "Reservoir Characterization of an Upper Permian Platform Carbonate in Preparation for a Horizontal-Well CO_2 Flood, South Cowden Unit, West Texas," was written and submitted to the Oklahoma Geological Survey (OGS) by Craig D. Caldwell. This paper was previously presented as a poster session at the March, 1996, meeting "Platform Carbonates of the Southern Midcontinent" sponsored by the OGS. The OGS is planning on publishing 1000 copies of the proceedings from this meeting.

Kimberly B. Dollens presented a talk entitled "Cost Optimization/Operations in WAG Flooding: E. Vacuum Grayburg and So. Cowden Units," and participated in a panel discussion on "Cost Optimization - Installation and Operations, " at the 2nd Annual Permian Basin CO_2 Conference in Midland, Texas, December 10-12, 1996.

Continued development of a South Cowden Unit Internet site for data and technology transfer was initiated. The prototype (for intra-company use only) was completed, but editing was not finalized for the Internet.

SPE Paper 37470, "The Evaluation of Two Different Methods of Obtaining Injection Profiles in CO_2 WAG Horizontal Injection Wells," written by Kimberly B. Dollens, Burl W. Wylie, James C. Shoumaker, Orjan Johannessen, and Phil Rice, was presented by Ms. Dollens at the 1997 SPE Production Operations Symposium, March 9-11, 1997, in Oklahoma City, Oklahoma. Ms. Dollens also presented this paper at the Phillips Petroleum Company Exploration and Production (E&P) Technical Symposium in Bartlesville, Oklahoma, April 2-4, 1997. The abstract is included as Attachment I.

James C. Shoumaker presented a poster session entitled "Drilling and Completions Considerations of Horizontal CO_2 Injection Wells - South Cowden Unit," at the Phillips Petroleum Company Exploration and Production (E&P) Technical Symposium in Bartlesville, Oklahoma, April 2-4, 1997. The abstract of this poster session is included as Attachment II.

Kimberly B. Dollens presented the project review at the U.S. Department Of Energy, National Petroleum Technology Office, Oil Technology and Gas Environmental Review on June 16, 1997, in Houston Texas.

LIST OF FIGURES

FIGURES

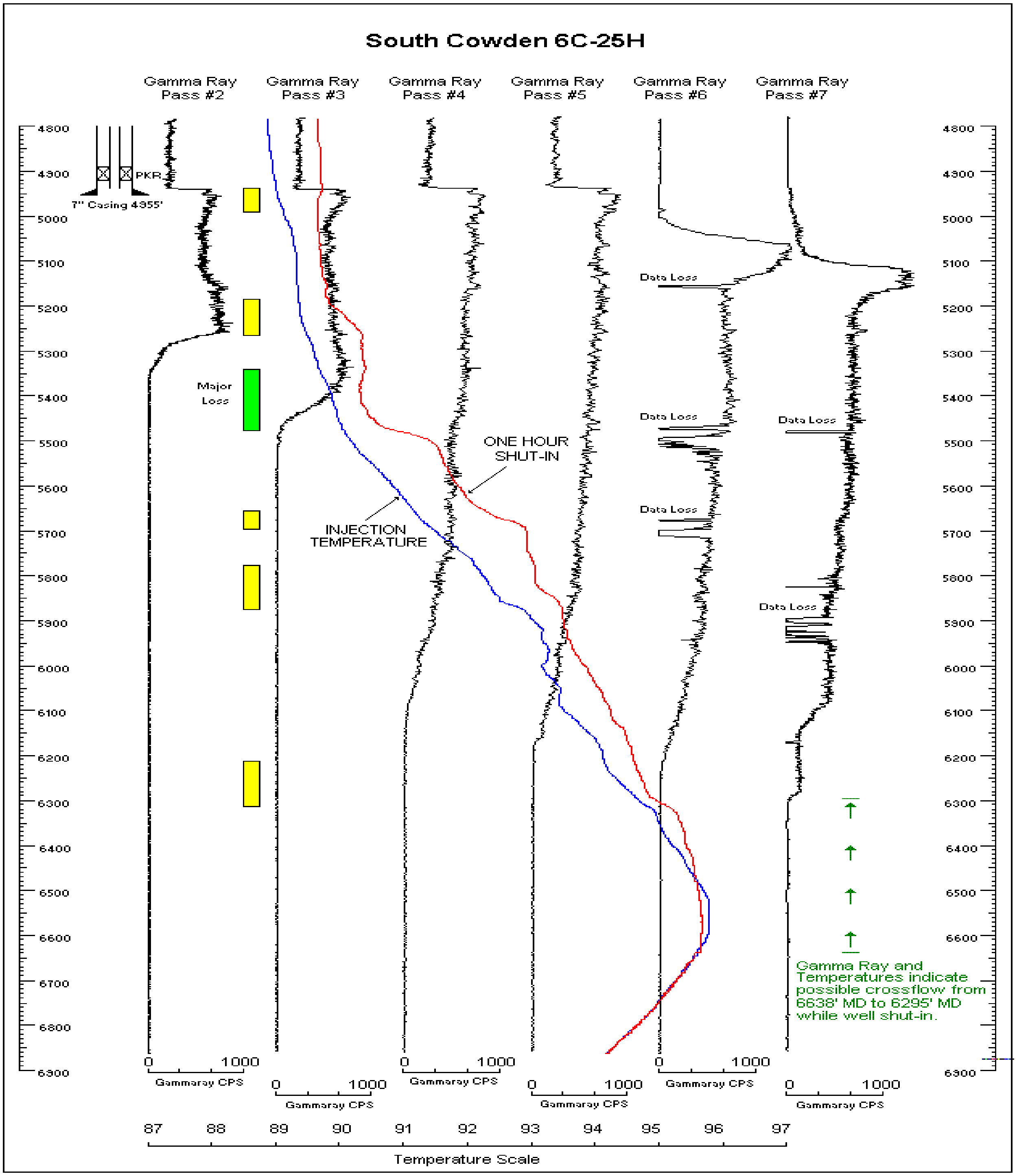


Figure 1 - Memory Logging Results Under Water Injection, Well 6C-25H

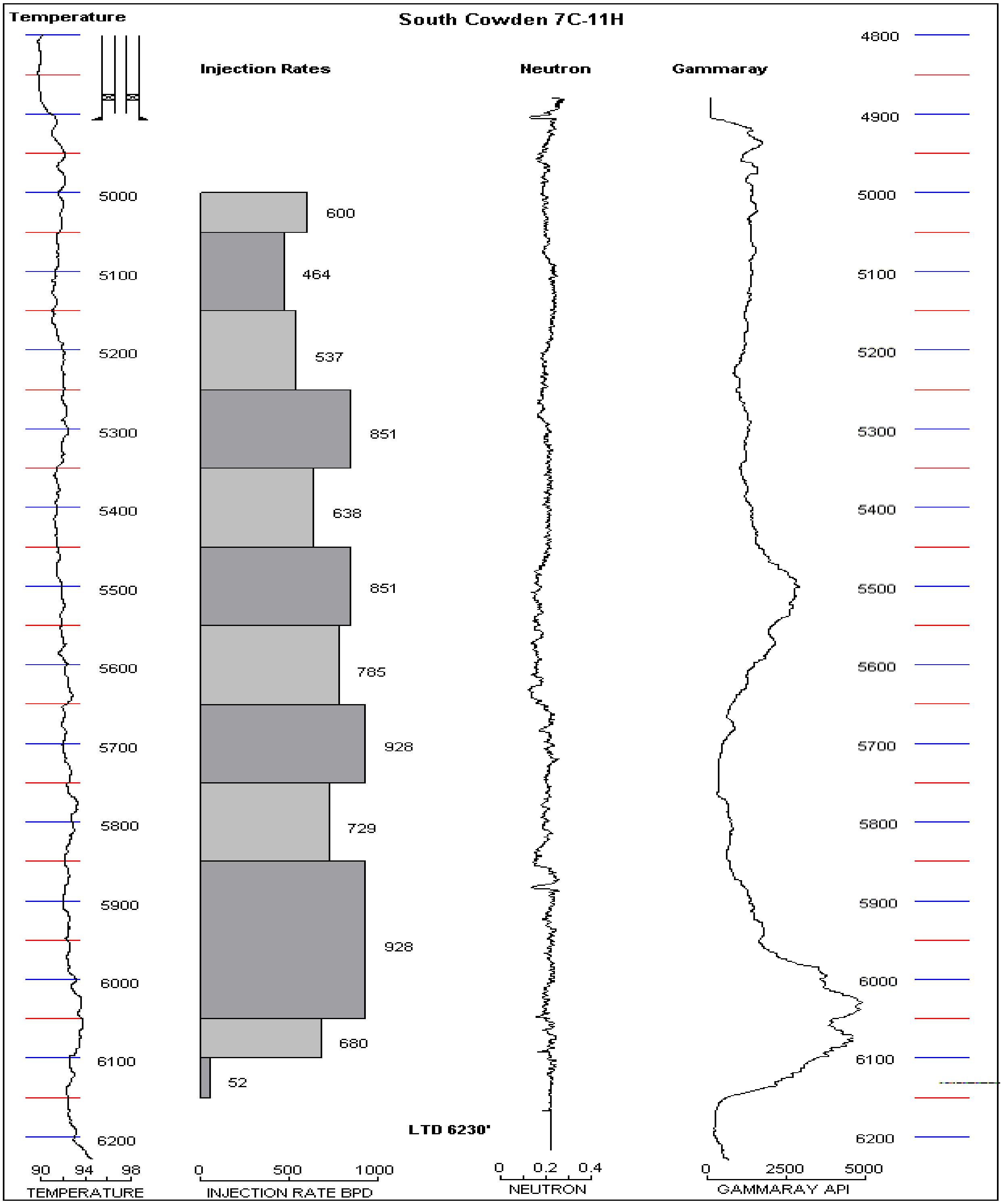


Figure 2 -Coiled Tubing and Wireline System Results under Water Injection, Well 7C-11H

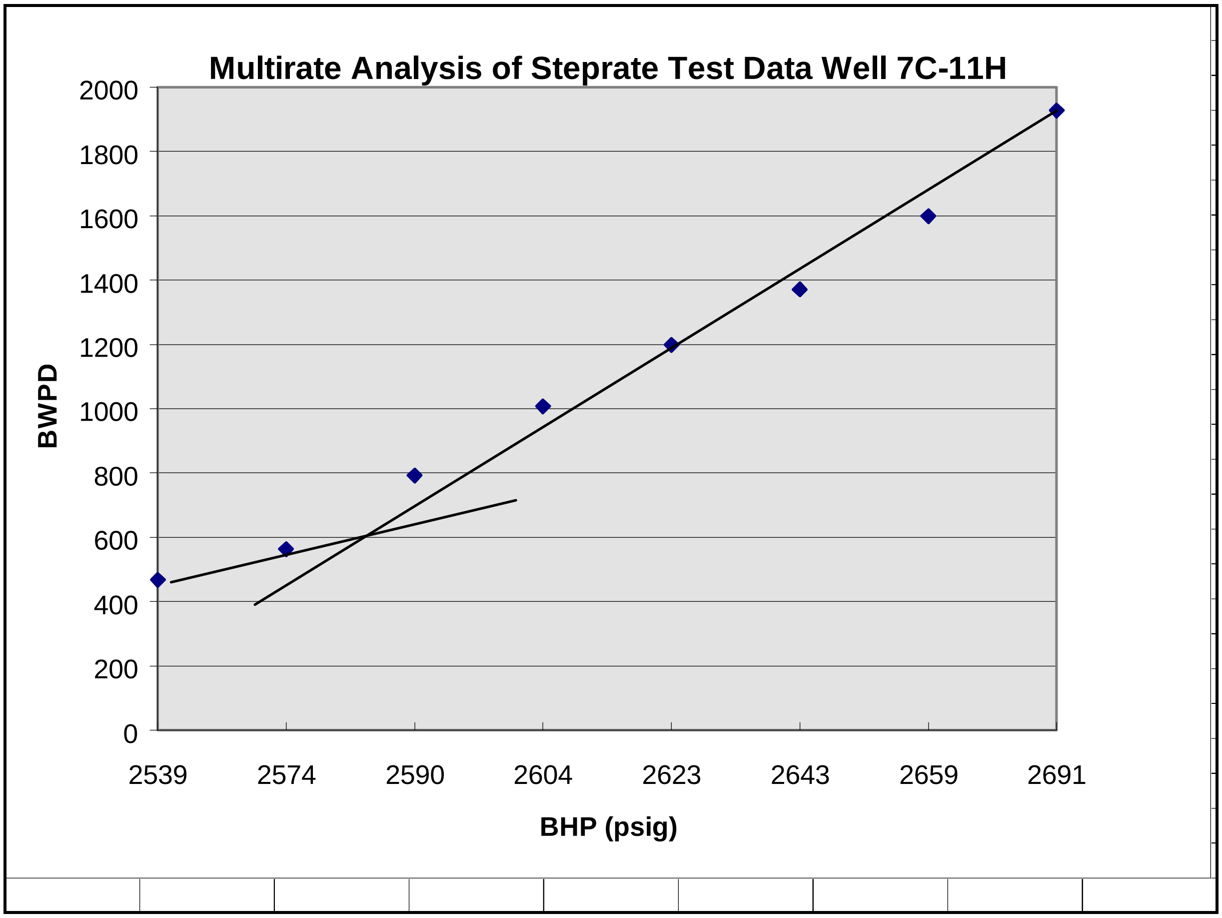


Figure 3 - Multi Rate Analysis of Step Rate Test Data, Well 7C-11H

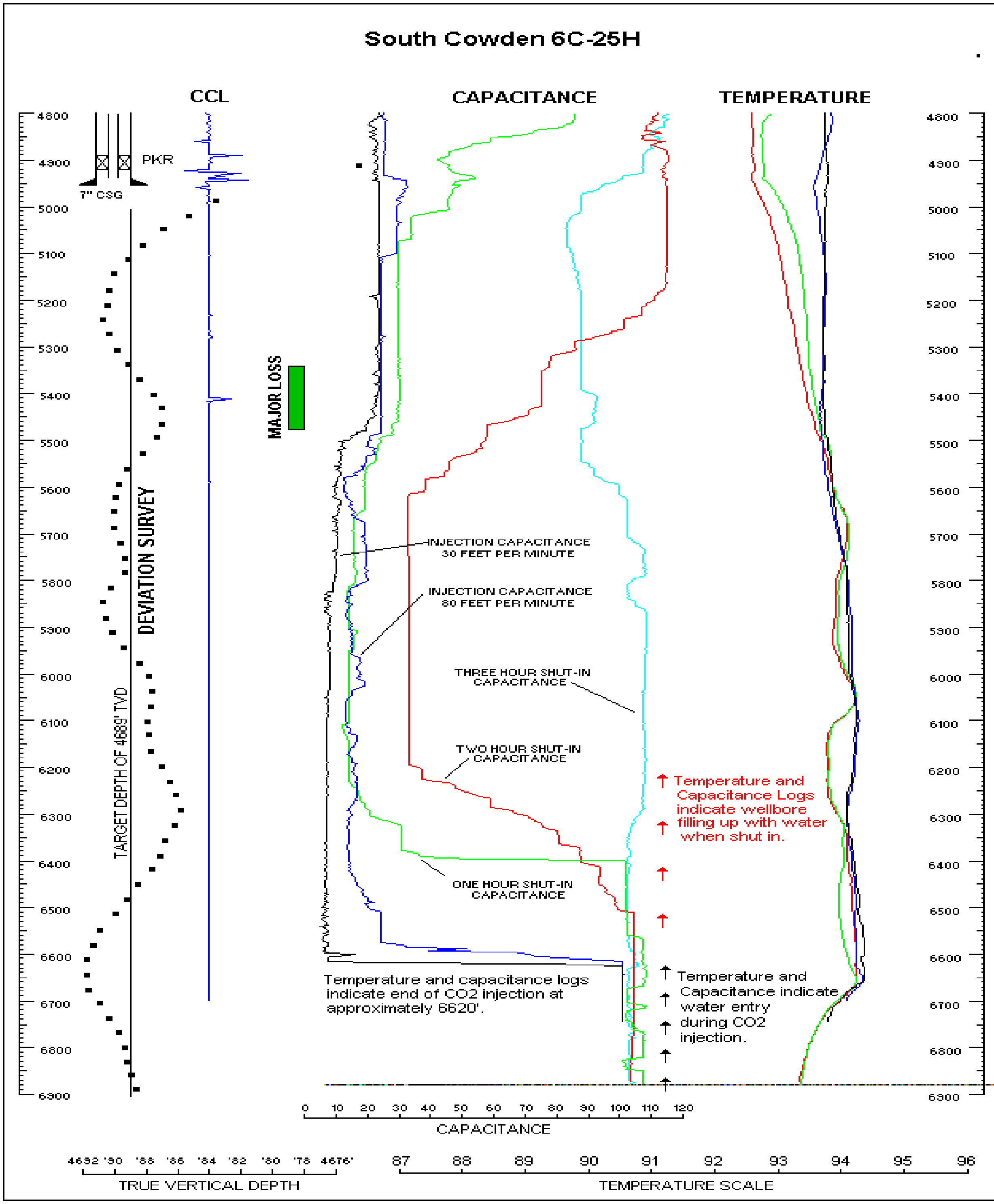


Figure 4 - Memory Logging Results under CO_2 Injection, Well 6C-25H

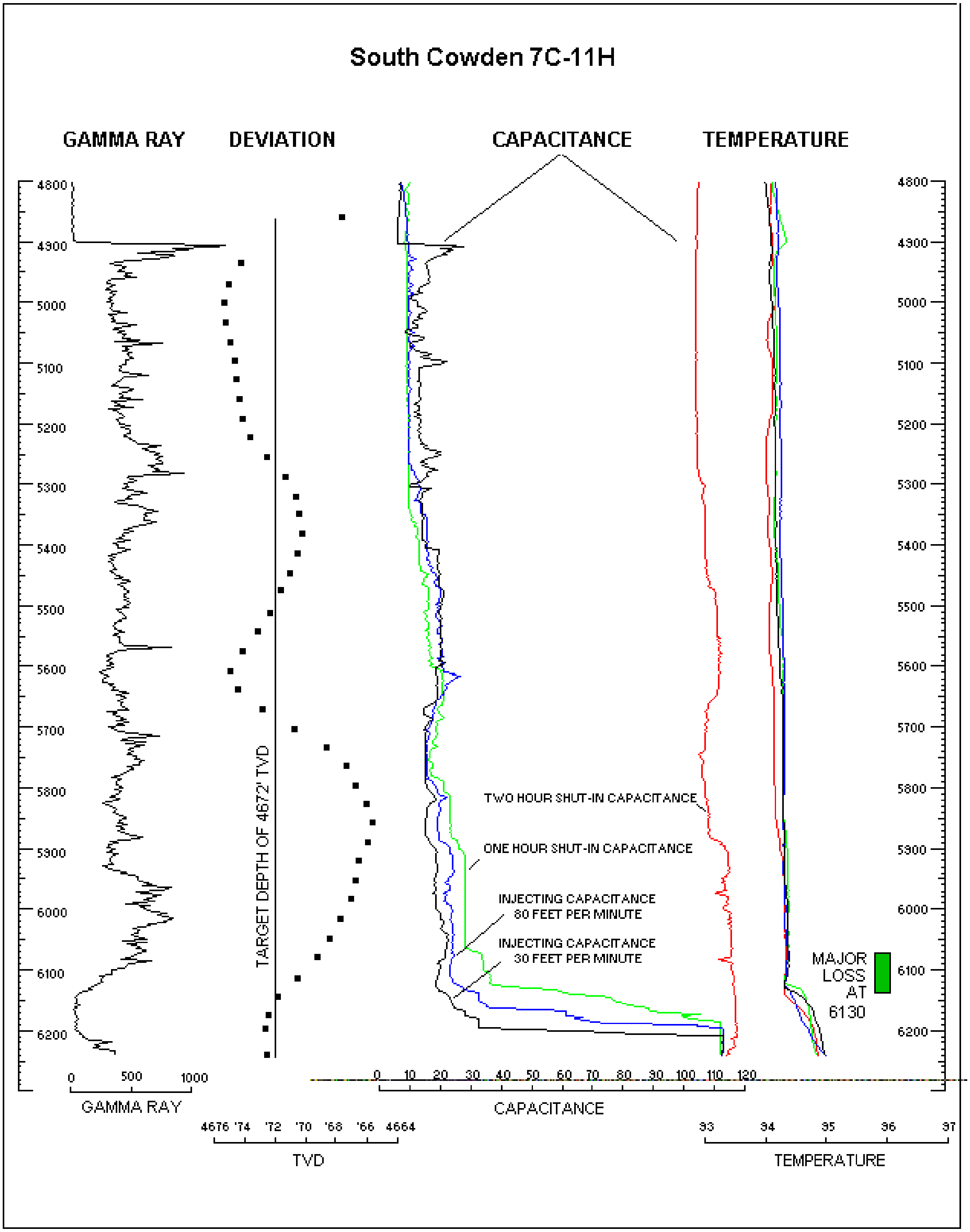


Figure 5 - Memory Logging Results under CO_2 Injection, Well 7C-11H

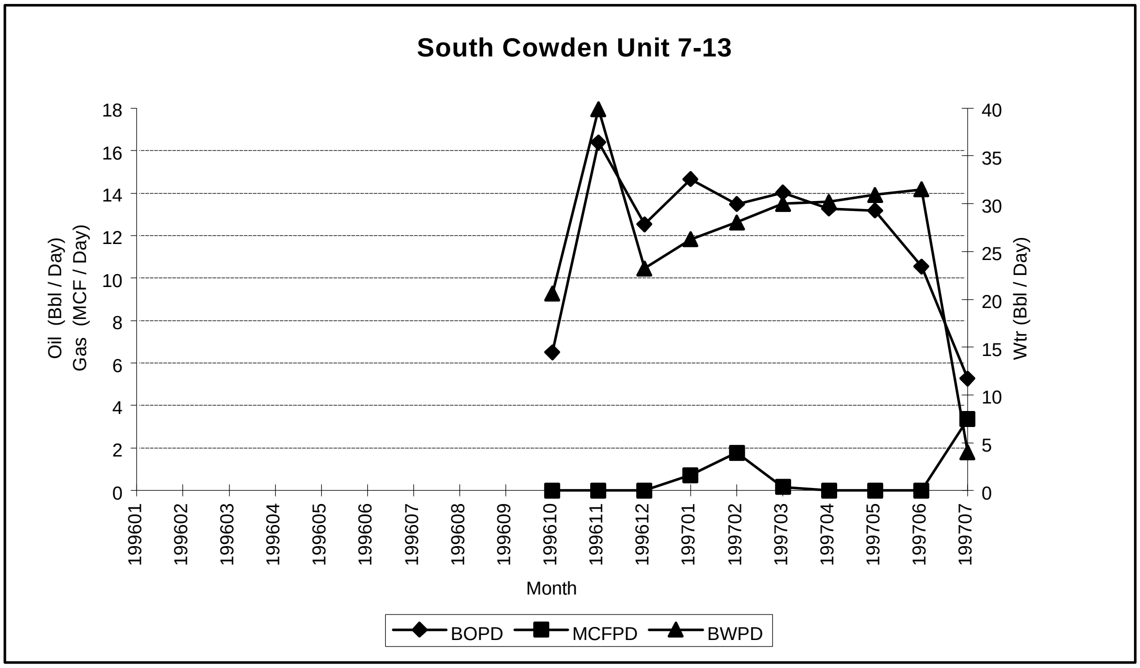


Figure 6- Daily Production Rate vs Time, Well 7-13

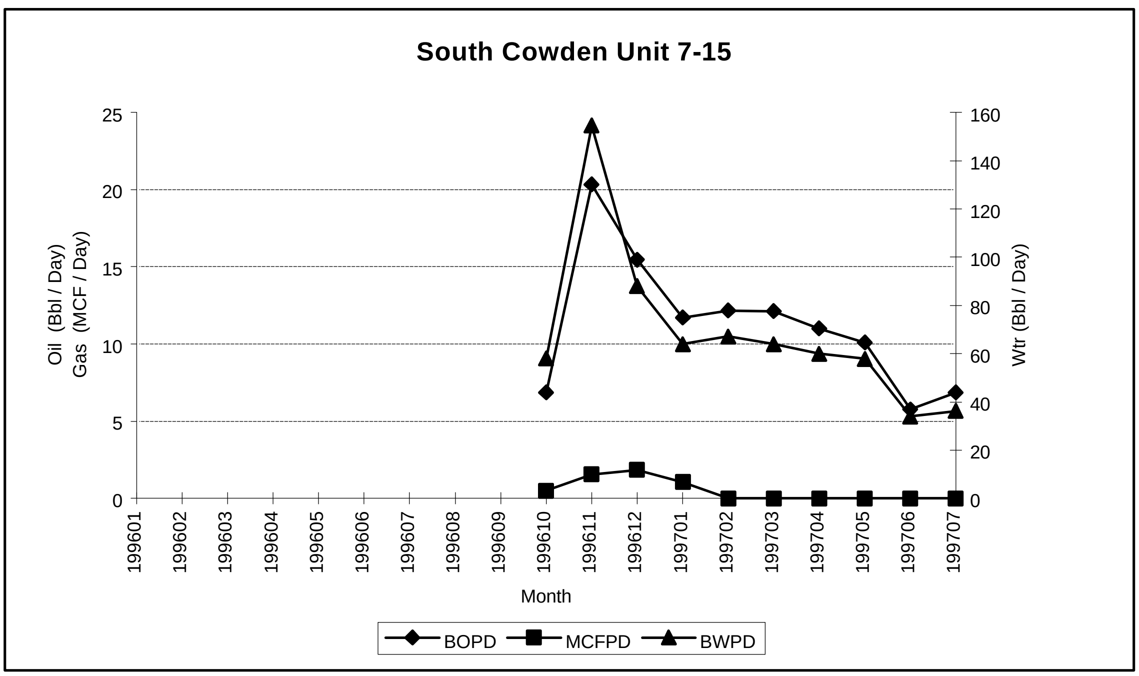


Figure 7 - Daily Production Rate vs Time, Well 7-15

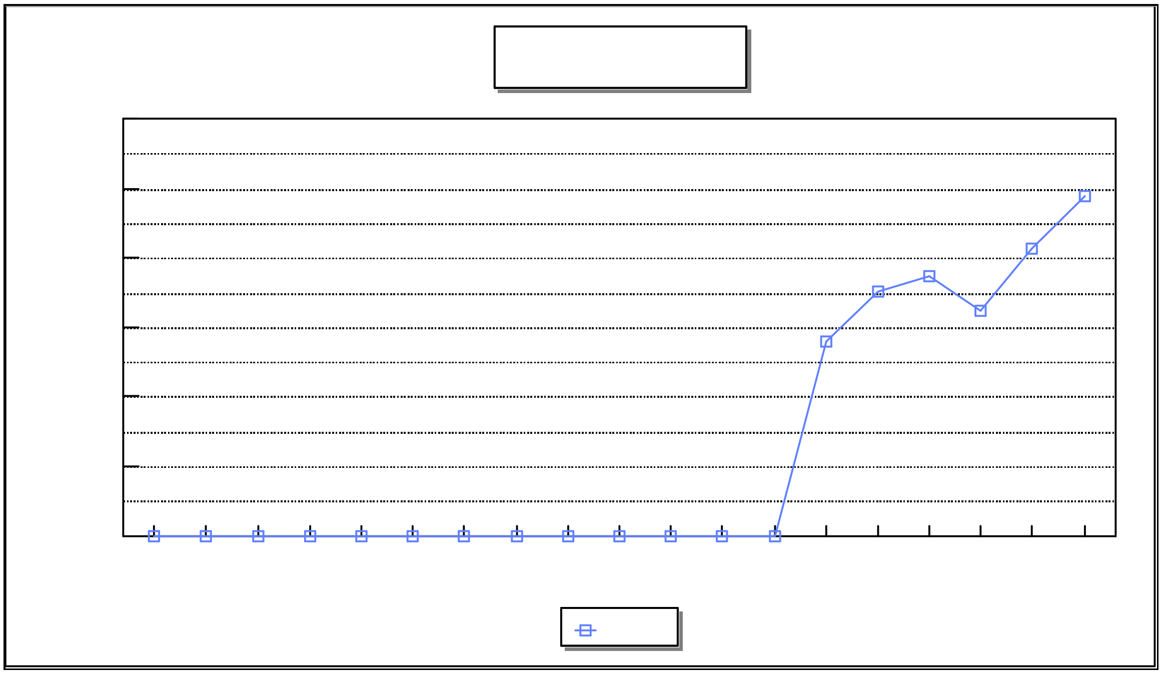


Figure 8 - Daily Water Injection Rate vs Time, Well 5-02

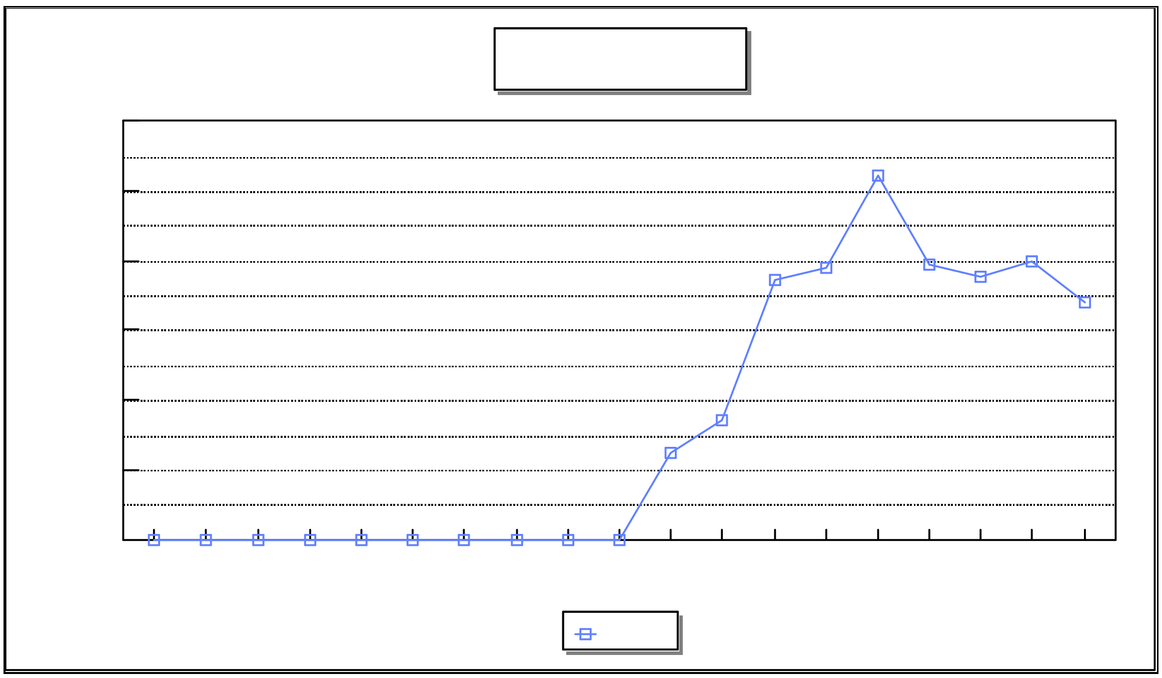


Figure 9 - Daily Water Injection Rate vs Time, Well 5-08

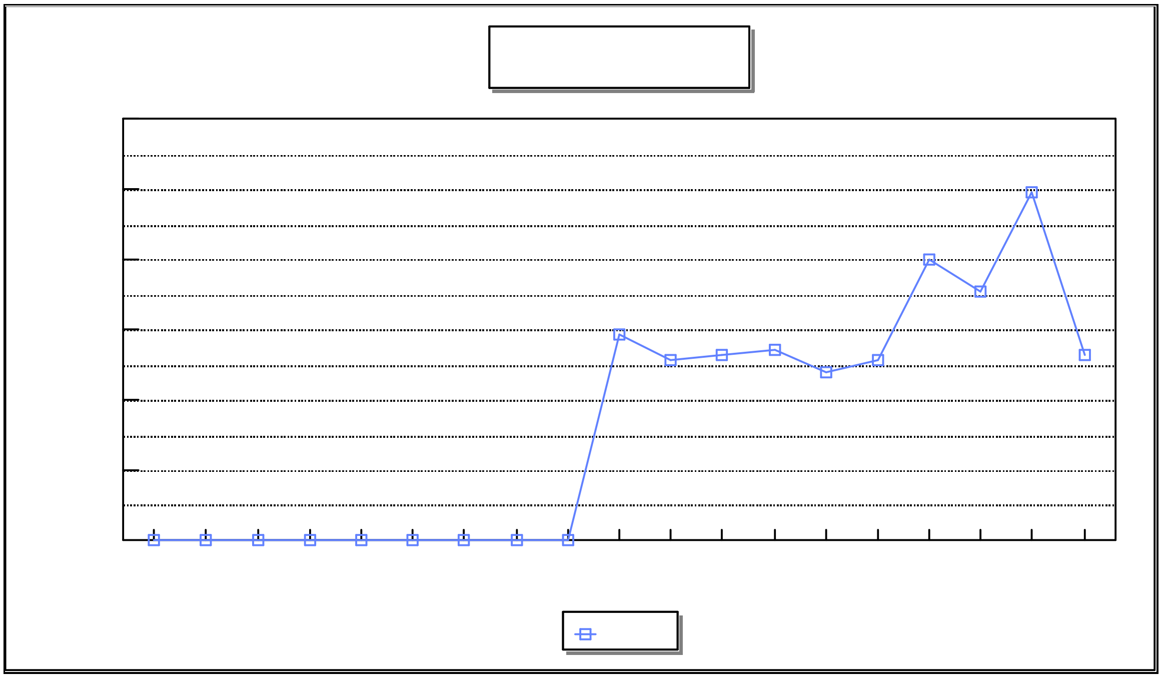


Figure 10 - Daily Water Injection Rate vs Time, Well 8-18

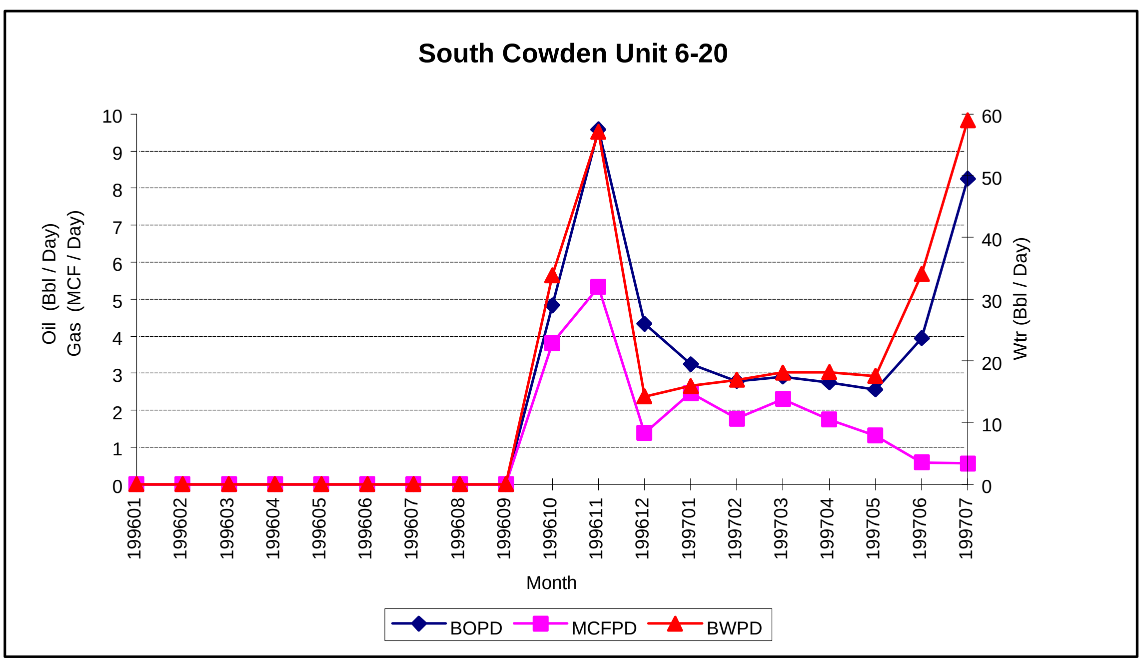


Figure 11 - Daily Production Rate vs Time, Well 6-20

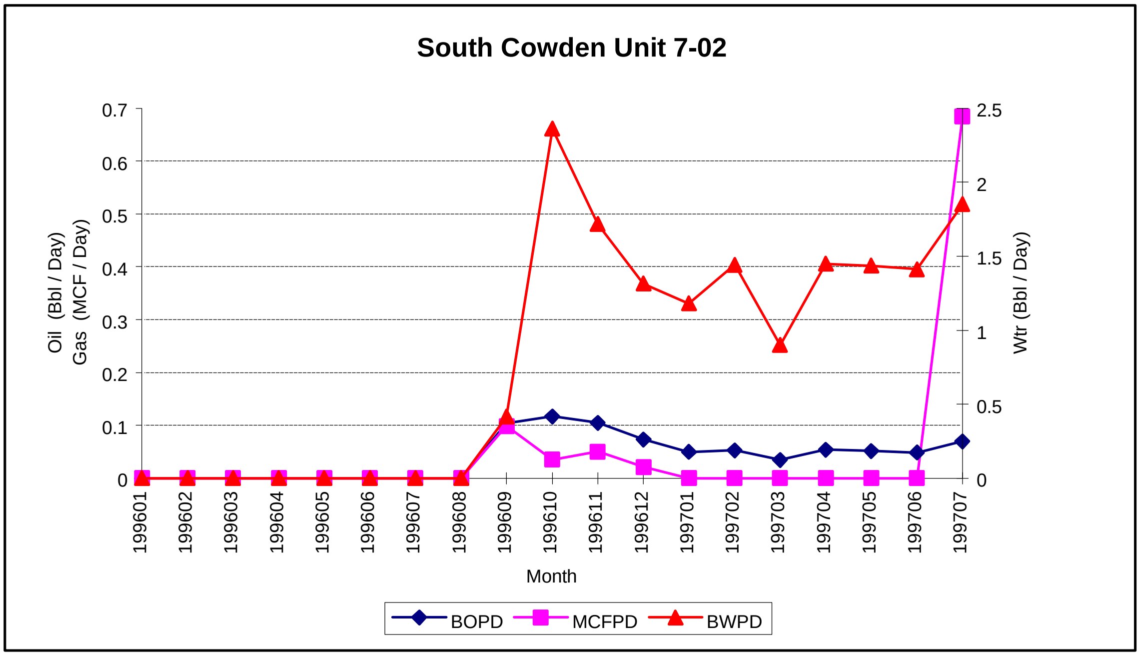


Figure 12 - Daily Production Rate vs Time, Well 7-02

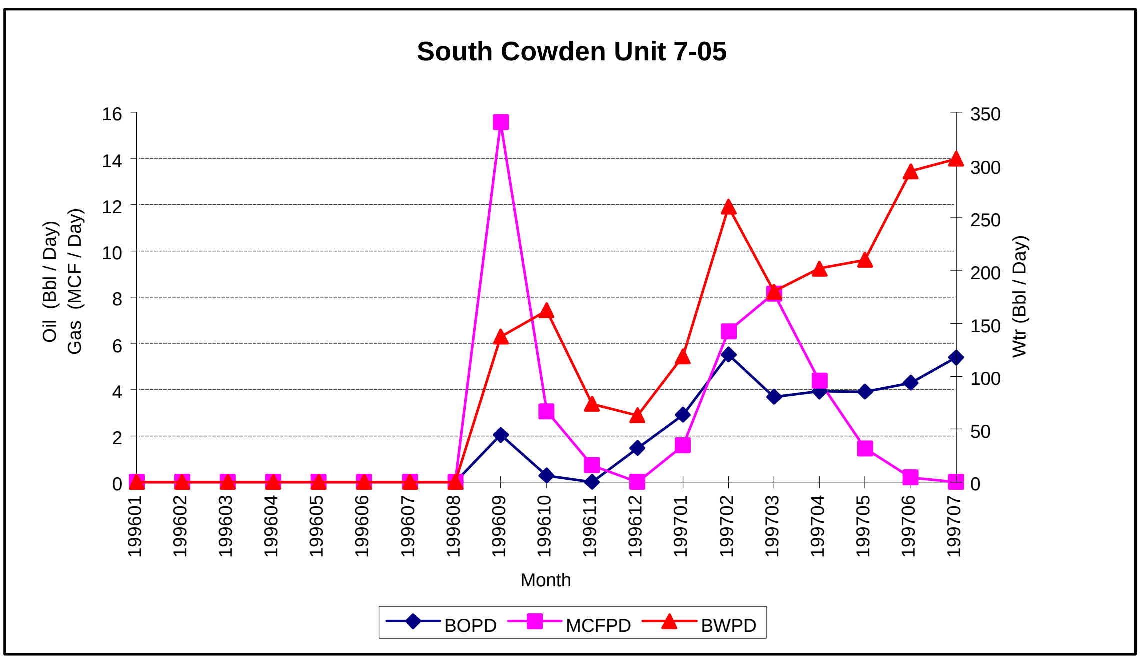


Figure 13 - Daily Production Rate vs Time, Well 7-05

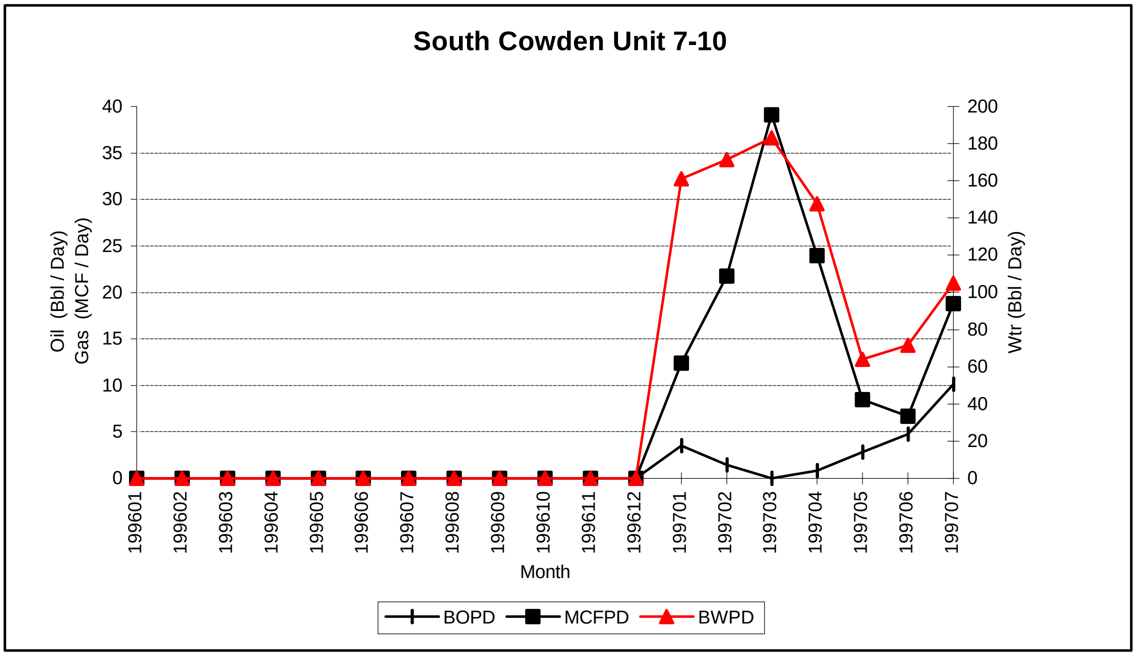


Figure 14 - Daily Production Rate vs Time, Well 7-10

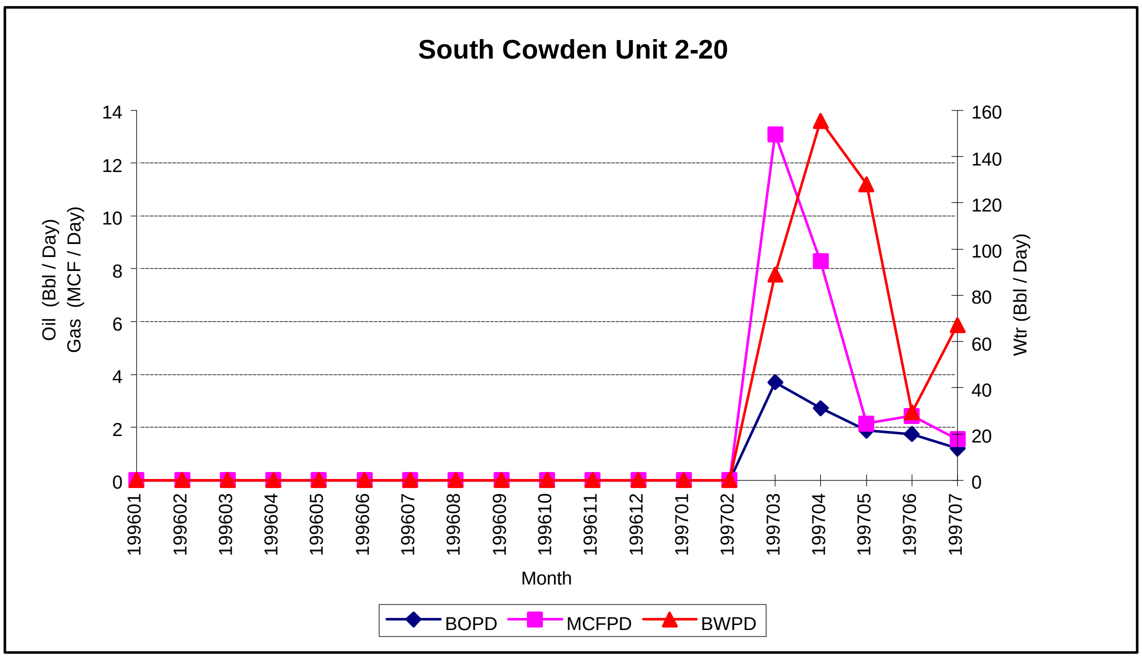


Figure 15 - Daily Production Rate vs Time, Well 2-20

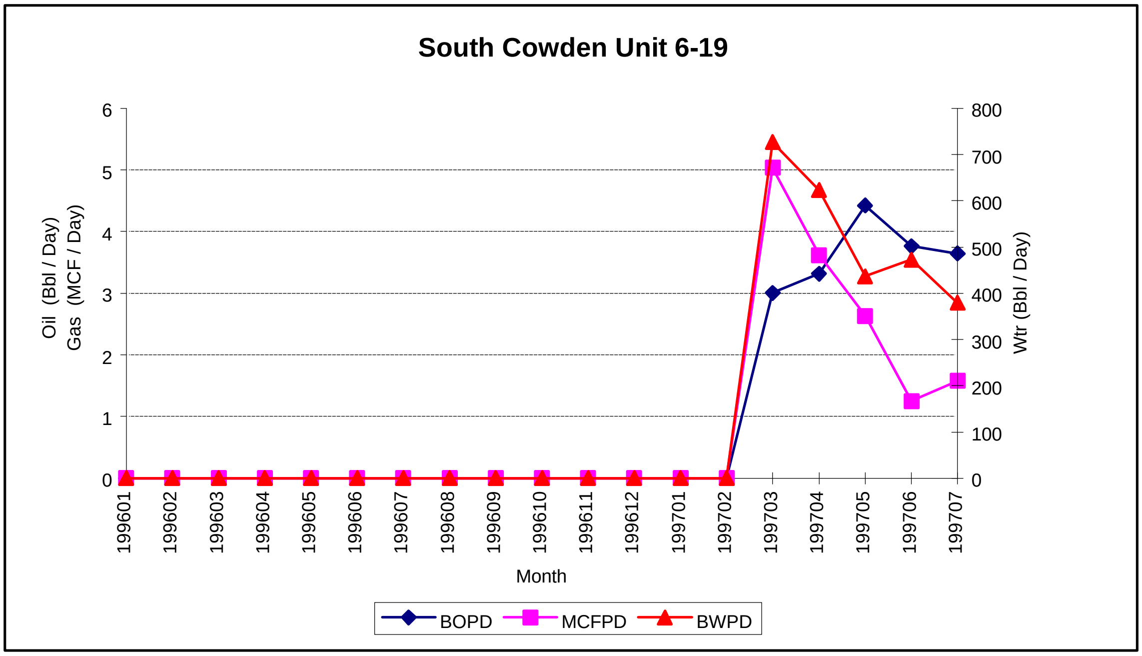


Figure 16 - Daily Production Rate vs Time, Well 6-19

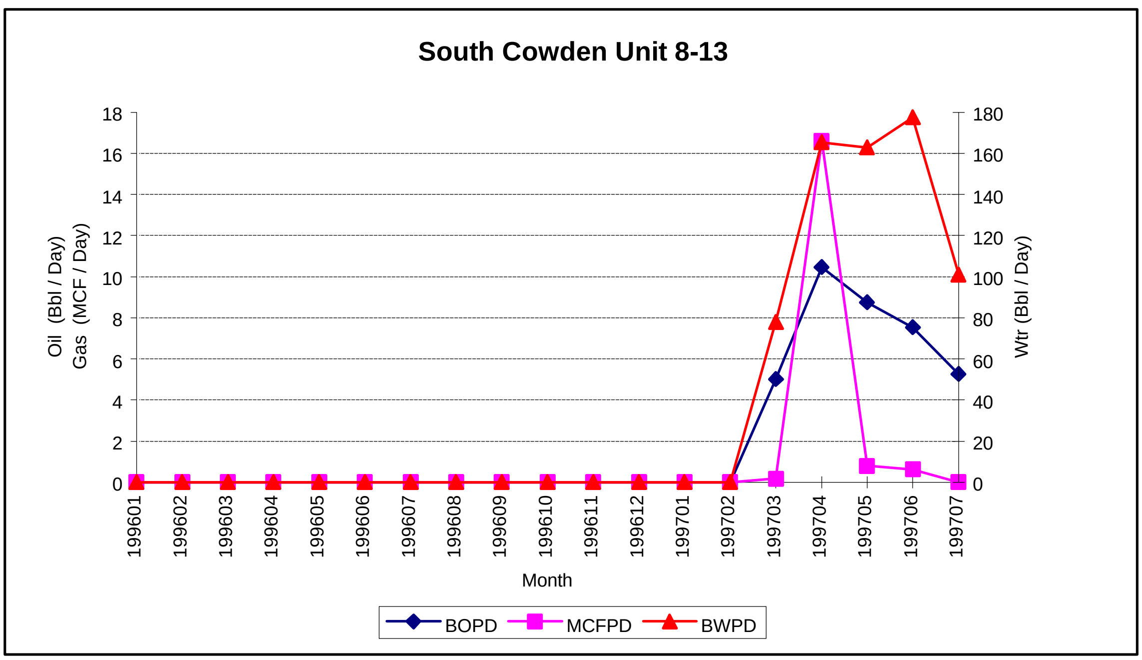


Figure 17 - Daily Production Rate vs Time, Well 8-13

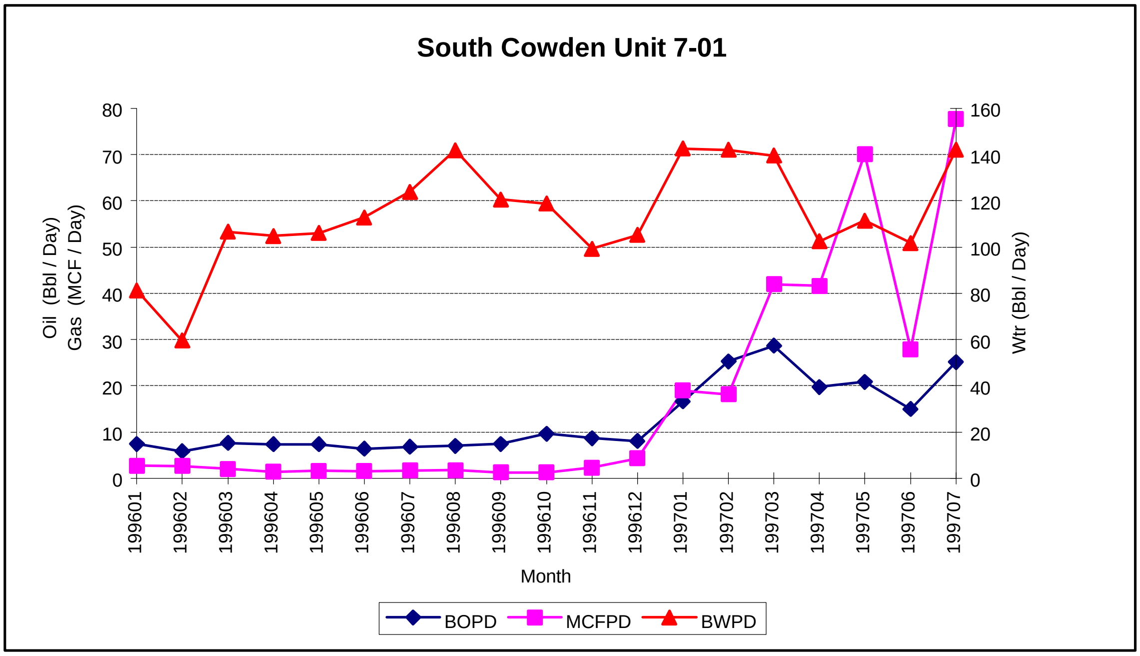


Figure 18 - Daily Production Rate vs Time, Well 7-01

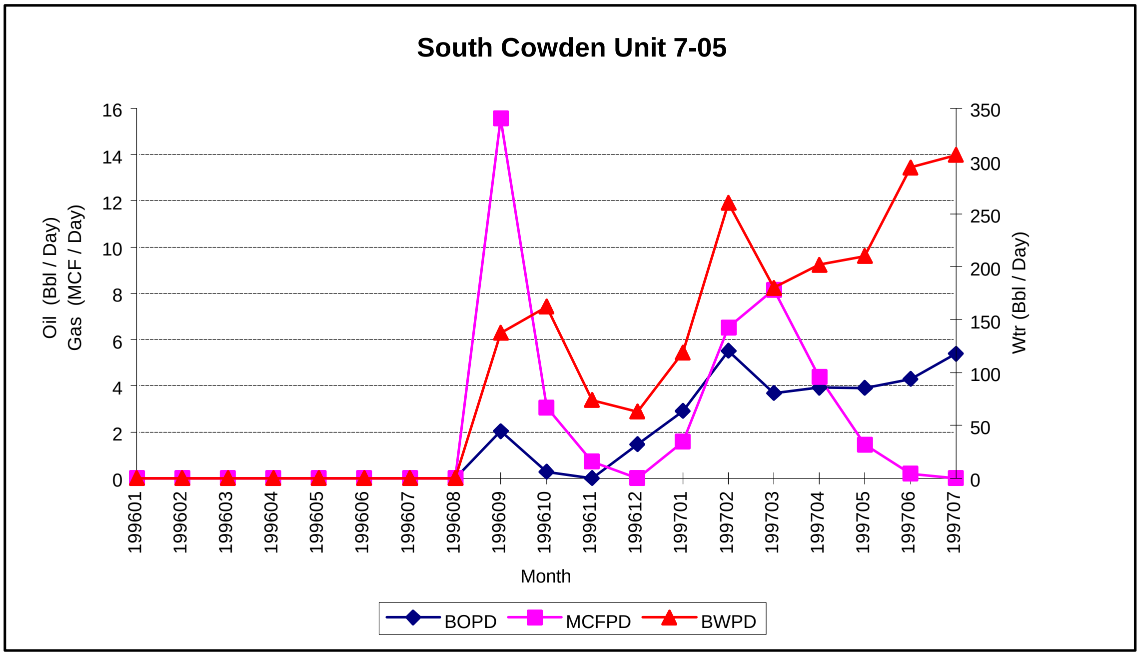


Figure 19 - Daily Production Rate vs Time, Well 7-05

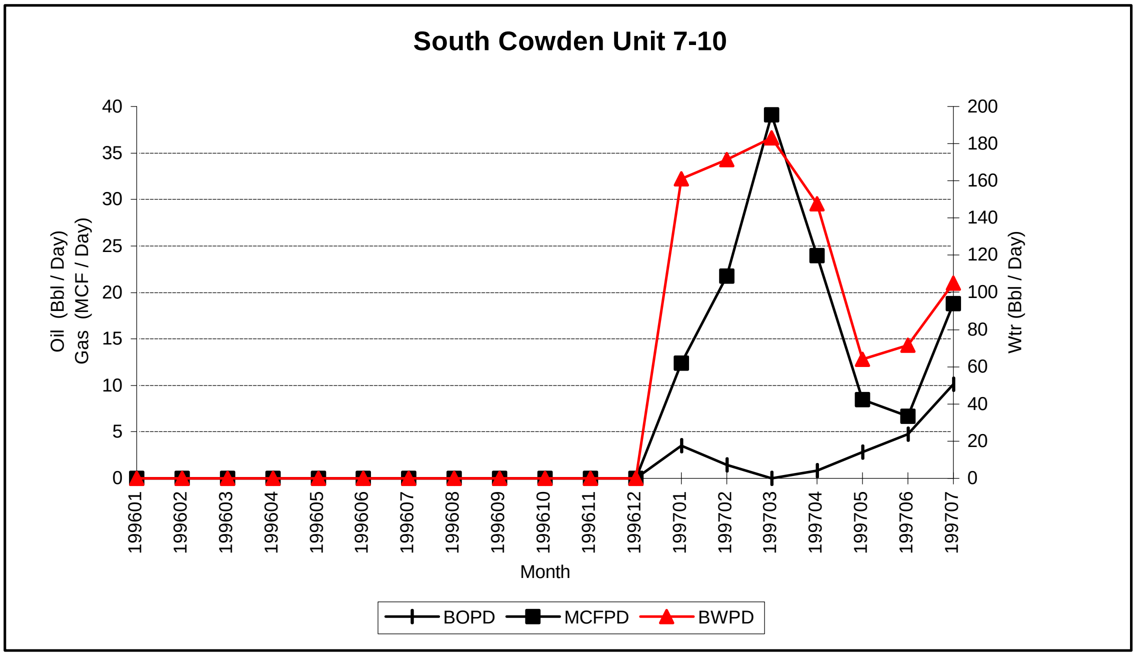
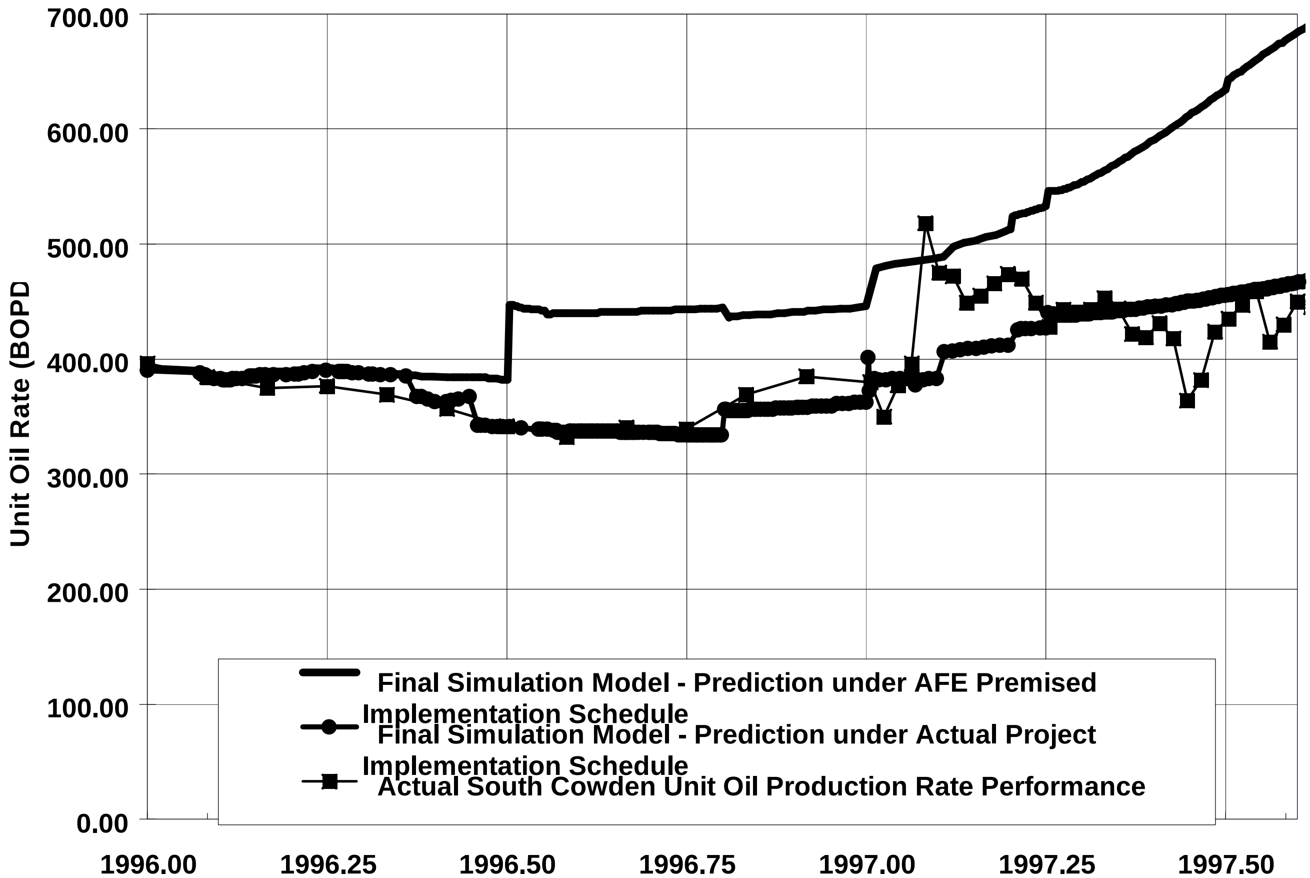


Figure 20 - Daily Production Rate vs Time, Well 7-10

Figure 21
Comparison Actual Unit Production vs Model Forecast



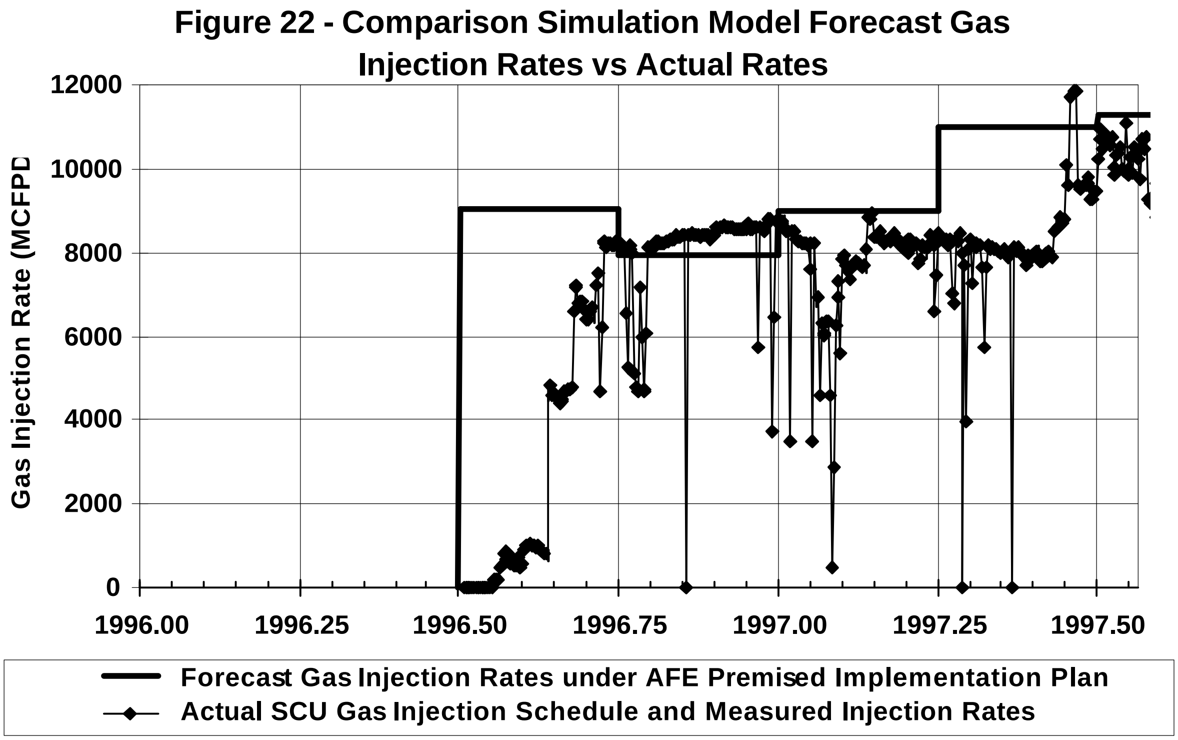


Figure 22 - Comparison Simulation Model Forecast Gas Injection Rates vs Actual Rates
Gas Injection Rate (MCFPD
12000
10000
8000
6000
4000
2000
0
1996.00
1996.25
1996.50
1996.75
1997.00
1997.25
1997.50
Forecast Gas Injection Rates under AFE Premised Implementation Plan
Actual SCU Gas Injection Schedule and Measured Injection Rates

Figure 23 - Comparison Forecast vs. Actual Injection Rates for Individual Injection Wells - First Quarter 1997

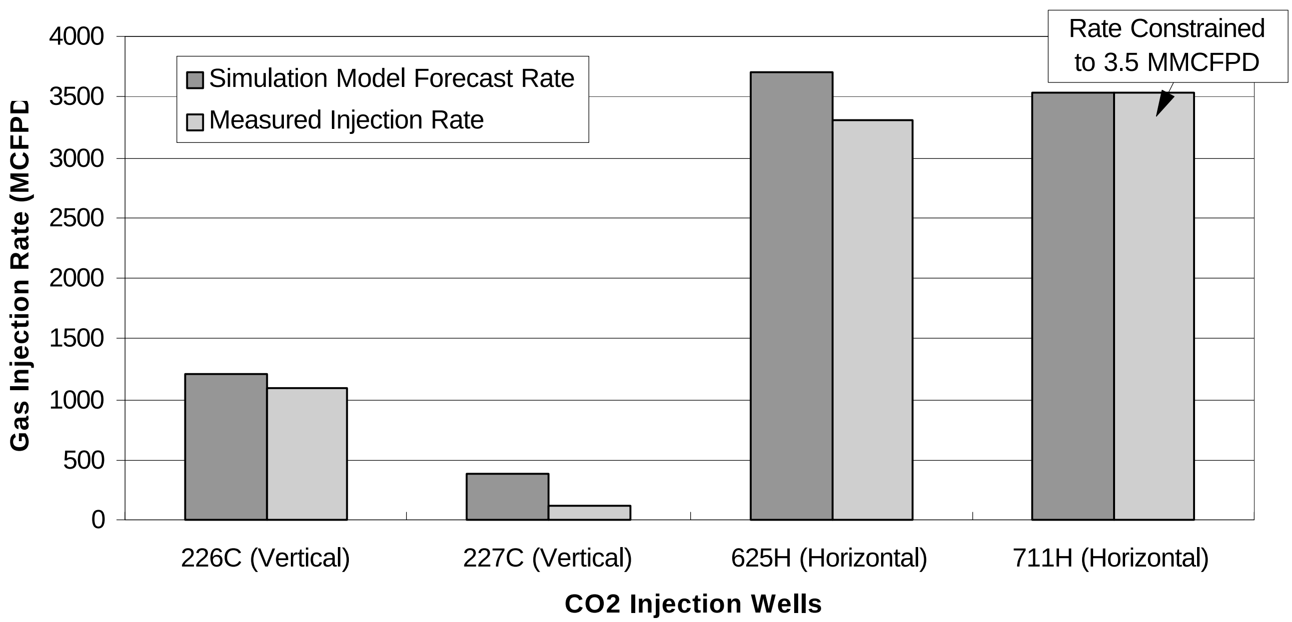


Figure 24 - South Cowden Unit Actual vs. Forecast CO2 Project Gas Production Performance

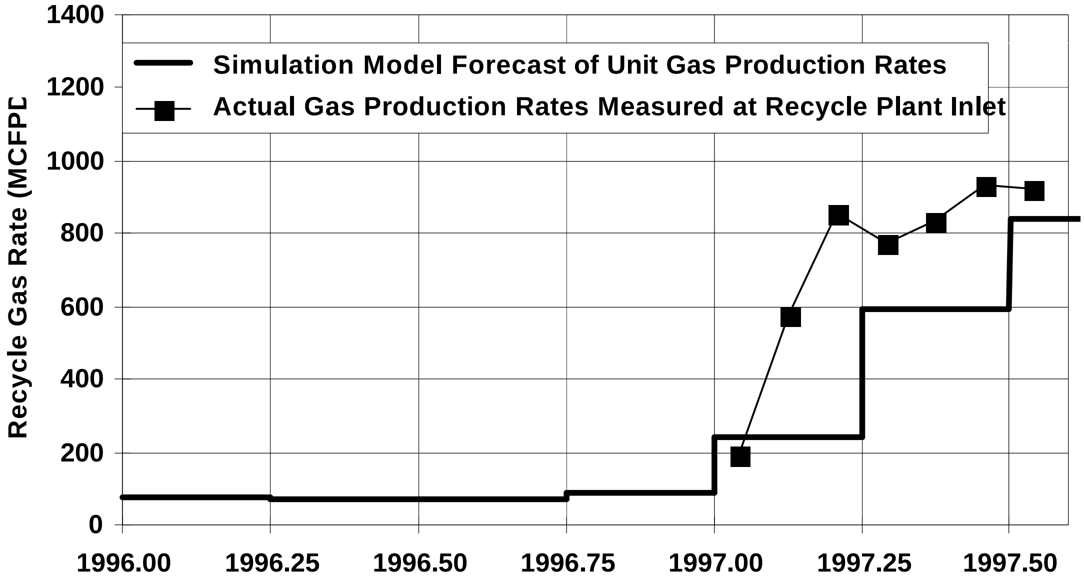


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Table 1

Bottom Hole Pressure Survey
Well 6C-25H
8/14/96

Shut-in 8/8/96 @ 9:38 A.M.

Depth (GL) feet	Pressure psig	Gradient psi/ft
0	340.70	
1000	801.30	0.4606
2000	1251.50	0.4503
3000	1703.30	0.4518
3676	2008.90	0.4521
4176	2245.40	0.4729

Elevation: KB+13’		GL	
Pressure Datum			
Top of Pay			
Tubing	3-1/2	Depth	4198
S.N.	4197	Packer	
Casing	7”	Depth	
Perforations		Open Hole	
Total Depth			
Formation		San Andres	
Casing Pressure		Pkr	
Tubing Pressure		343	
Top of Fluid		None	
Top of Water		None	
Hours Shut-in			
Temp @ 4176’		92.36 deg F	
Last Test Date			
Press last Test Date			
B.H.P. Change			

Table 2

Bottom Hole Pressure Survey
Well 6C-25H
10/11/96

Shut-in 10/8/96 @ 11:14:30

Depth (GL) feet	Pressure psig	Gradient psi/ft
0	958.00	
250	1049.80	0.3670
500	1132.40	0.3304
750	1214.70	0.3292
1000	1298.40	0.3350
2000	1636.80	0.3384
3000	1985.00	0.3483
4000	2340.00	0.3549
4197	2398.60	0.2979

Elevation:	KB+17’	GL	
Pressure Datum			
Top of Pay			
Tubing	3-1/2	Depth	4198
S.N.	4197	Packer	
Casing		Depth	
Perforations		Open Hole	
Total Depth			
Formation		San Andres	
Casing Pressure			
Tubing Pressure		951	
Top of Fluid		None	
Top of Water		None	
Hrs Shut-in			
Temp @ 4197		93.46 deg F	
Last Test Date			
Press last Test Date			
B.H.P. Change			

Table 3

Bottom Hole Pressure Survey
Well 7C-11H
8/20/96

Shut-in 8/15/96 @ 12:14

Depth (GL) feet	Pressure psig	Gradient psi/ft
0	307.10	
1000	769.10	0.4620
2000	1222.20	0.4530
3000	1676.10	0.4541
4000	2131.70	0.4556
4214	2222.90	0.4259

Elevation: KB+13’		GL	2934
Pressure Datum			
Top of Pay			
Tubing	3-1/2	Depth	
S.N.	4226	Packer	4878
Casing	7	Depth	
Perforations		Open Hole	
Total Depth			
Formation		San Andres	
Casing Pressure			
Tubing Pressure		306	
Top of Fluid		None	
Top of Water		None	
Hrs Shut-in			
Temp @ 4214		92.38 deg F	
Last Test Date			
Press last Test Date			
B.H.P. Change			

Table 4

Bottom Hole Pressure Survey
Well 7C-11H
10/15/96

Shut-in 102/96 @ 14:31

Depth (GL) feet	Pressure psig	Gradient psi/ft
0	1004.0	
250	1096.3	0.3692
500	1179.5	0.3329
750	1263.7	0.3367
1000	1346.7	0.3320
2000	1589.4	0.3427
3000	2039.7	0.3532
3237	2123.4	0.3532
4000	2396.5	0.3580
4207	2464.0	0.3260

Elevation: KB	2951	GL	2934
Pressure Datum			
Top of Pay			
Tubing	3-1/2	Depth	4226
S.N.	4225	Packer	
Casing		Depth	
Perforations		Open Hole	
Total Depth			
Formation		San Andres	
Casing Pressure			
Tubing Pressure		1004 gauge	
Top of Fluid		None	
Top of Water		None	
Hrs Shut-in		98.5	
Temp @ 4214		93.5 deg F	
Last Test Date			
Press last Test Date			
B.H.P. Change			

ATTACHMENTS

Attachment	Description
I	Abstract submitted entitled "The Evaluation of Two Different Methods of Obtaining Injection Profiles in CO_2 WAG Horizontal Injection Wells".
II	Abstract submitted entitled "Drilling and Completions Considerations of Horizontal CO_2 Injection Wells - South Cowden Unit".

ATTACHMENTS

ATTACHMENT I

TITLE: THE EVALUATION OF TWO DIFFERENT METHODS OF OBTAINING INJECTION PROFILES IN CO_2 WAG HORIZONTAL INJECTION WELLS

AUTHORS: Kimberly B. Dollens, James C. Shoumaker, Burl W. Wylie, Phil Rice, and Orjan Johannessen

Two different methodologies were employed in obtaining injection profile surveys in two CO_2 water-alternating-gas (WAG) horizontal injection wells in the South Cowden Unit (SCU) CO_2 project. Both methods were used once during an initial water injection period to establish a baseline profile. Then, the first method was utilized on both of the horizontal injection wells during a CO_2 injection period. The first method utilized a coiled tubing conveyed, memory-based logging system, including a correlation gamma ray and collar locator log; injection and shut-in temperature, capacitance, flowmeter and pressure gradient; and interface tag. The second method utilized a logging and injection program wherein coiled tubing and wireline were run in the injection well with a Y-block and coiled tubing side-entry assembly attached to the coiled tubing below the spot valve. The tool consisted of a positive and negative gamma ray and temperature tool, and utilized a slug of more than one gallon of radioactive gel rather than the standard injection volume of approximately 50 cc or 1 cc per station. Actual field results are reviewed, and the two methodologies discussed for application in CO_2 WAG horizontal injection systems.

ATTACHMENT II

TITLE: DRILLING & COMPLETION CONSIDERATIONS OF HORIZONTAL CO_2 INJECTION WELLS - SOUTH COWDEN UNIT

AUTHORS: James Shoumaker and Sam Hyden

The South Cowden Unit 6C-25H and 7C-11H were drilled as horizontal CO_2 injection wells. The horizontal wells were an essential component of the economic viability of the tertiary recovery project. The CO_2 water-alternating-gas (WAG) injection well trajectories were designed to optimize reservoir performance. The trajectories of the 6C-25H and 7C-11H were drilled with a 12 degree/110 foot build-up rate, 6-1/8" openhole lateral lengths -1 1935' (Azimuth: 76 degrees East of True North) and 1337' (Azimuth : 65 degrees West of True North), respectively. The wells were designed mechanically to optimize well injection performance and maximize duration of their utility due to the required CO_2 service. Both wells were equipped with 9-5/8", 36 ppf, J-55 surface casing; 7", 20 ppf, J-55 production casing through the curve; and injection packer/tubing/wellhead designed for CO_2 service. The wells were stimulated with 15% HCL acid by coiled tubing acid washing sweeps. Current injection is approximately 3.5 MMscfd of CO_2 per well, which is essentially a three fold increase in injectivity of a single vertical injection well in the same field. This presentation will review the planning, designing, and techniques utilized to meet the South Cowden Unit horizontal CO_2 injection well drilling/completion project.